Strategic Evaluation of RD&D Needs and Opportunities for US Mid-Sized Gas Turbines in Intermediate Load Applications

Final Report

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Table of Contents

Acronyms

ADL	Arthur D. Little
AEO	Annual Energy Outlook
AGC	Automatic Generation Control
AMGT	Advanced Mid-Sized Gas Turbine
ATS	Advanced Turbine System
CAGT	Collaborative Advanced Gas Turbine
CEC	California Energy Commission
ECAR	East Central Area Reliability Coordination Agent
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
GRI	Gas Research Institute
GTA	Gas Turbine Association
GTCC	Gas Turbine Combined Cycle
HHV	Higher Heating Value
ISO	Independent System Operator
LHV	Lower Heating Value
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
mgd	Millions of gallons per day
NERC	North American Electric Reliability Council
PJM	Pennsylvania, New Jersey, Maryland Interconnection
PX	Power Exchange
RAMD	Reliability, Availability, Maintainability, & Durability
SCGT	Simple Cycle Gas Turbine
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
T&D	Transmission and Distribution
T/E	Thermal to Electric
UDI	Utility Data Institute
WSCC	Western Systems Coordinating Council

Table of Contents

DOE and CEC retained Arthur D. Little to examine the intermediate load market opportunity for Advanced Mid-sized Gas Turbine (AMGT) technology.

- AMGT technology is used in this report to describe a class of a gas turbine technology that meets or exceeds specifically defined cost, performance and operability characteristic needs for mid-sized range applications particularly intermediate load.
- The report does not attempt to define the technology that will achieve these characteristics.
- The main objectives of the study are the following:
  - Characterize the intermediate load market by identifying key drivers and possible end-states,
  - Estimate the market potential for AMGT in intermediate load application,
  - Estimate the public benefits that would result from the adoption of AMGT,
  - Gauge the level of interest from gas turbine manufacturers, and
  - Develop recommendations for going forward.
- This study focuses on the characteristics of the U.S. market from 2005–2015.

AMGT technology would have higher efficiency than simple cycle gas turbines (SCGT) and lower capital costs than combined cycle gas turbines (GTCC).

AMGT Efficiency

	Efficiency (LHV)		Efficiency (LHV)
SCGT*	33% – 42%	**GTCC****	52% – 61%
AMGT	47% – 50%	**AMGT**	47% – 50%
Increase	+12% – +52%	**Increase**	-4% – -23%

AMGT Installed Costs

	Installed Cost ($/kW)		Installed Cost ($/kW)
SCGT*	225 – 350	**GTCC****	500 – 800
AMGT	250 – 300	**AMGT**	250 – 300
Reduction	-29% – +33%	**Reduction**	-33% – -70%

* >30 MW ** >100 MW, includes ATS

Advanced Mid-sized Gas Turbine Flexible Attributes

- 30–150 MW size range
- Rapid cold start capability (<10 minutes) and improved ramp rate
- Improved part load efficiency
- Design for optimum cycling operation
- Rapid installation time
- Design for optimum cycling operation
- Modular
- <5 PPM NO_x
- Low water use

In addition, it would have several “flexible” attributes that would make it more attractive than either SCGT or GTCC in some applications.

Arthur D. Little identified six broad classes of applications and sixteen different needs that might benefit from AMGT technology.

Application Classes	Application Requirements
Intermediate Load	Daily
	Weekly
	Seasonal
Peaking	Daily
Repowering	Feedwater Preheating
	Full Brownfield
Ancillary Services	Regulation, AGC, Voltage Support
	Spinning Reserve
	Non-Spinning Reserve
	Replacement/Operating Reserve, Black Start
	Transmission Congestion
Cogen	High T/E Ratio
	Low T/E Ratio
Green Power	Dedicated Biomass
	Cycle Hybrid
	Project Integration

For each of these top six applications, technical market potential estimates were obtained from previous studies and verified using other independent sources.

	Estimated Technical Market* Potential (GW)	Comments
Intermediate	260–290	A combination of load growth, replacement / retirement, and displacement market. Collaborative Advanced Gas Turbine Program report: “Flexible Mid-sized Gas Turbine - Preliminary Market Analysis” , October 1997.
Peaking	80–95	Current peaking units (<500 hours per year) with adjustment for load growth based on NERC projections. UDI database.
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Ancillary Services**	80–90	Based on NERC’s reserve margin recommendations for summer peak demand, NERC’s forecasted growth for reserve margin and ADL estimates.
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Green Power	10–75	Renewable energy capacity from AEO 98. Applied multiplying factor of 10 for cycle hybrid and project integration.

* Technical market: all applications requiring the basic function the new technology offers
** Ancillary service may not be a market by itself but could lead to an increase in intermediate market.
Note: These market numbers are not necessarily additive.

These numbers represent the technical market potential for the advanced mid-sized gas turbine in the 2005–2015 time frame.

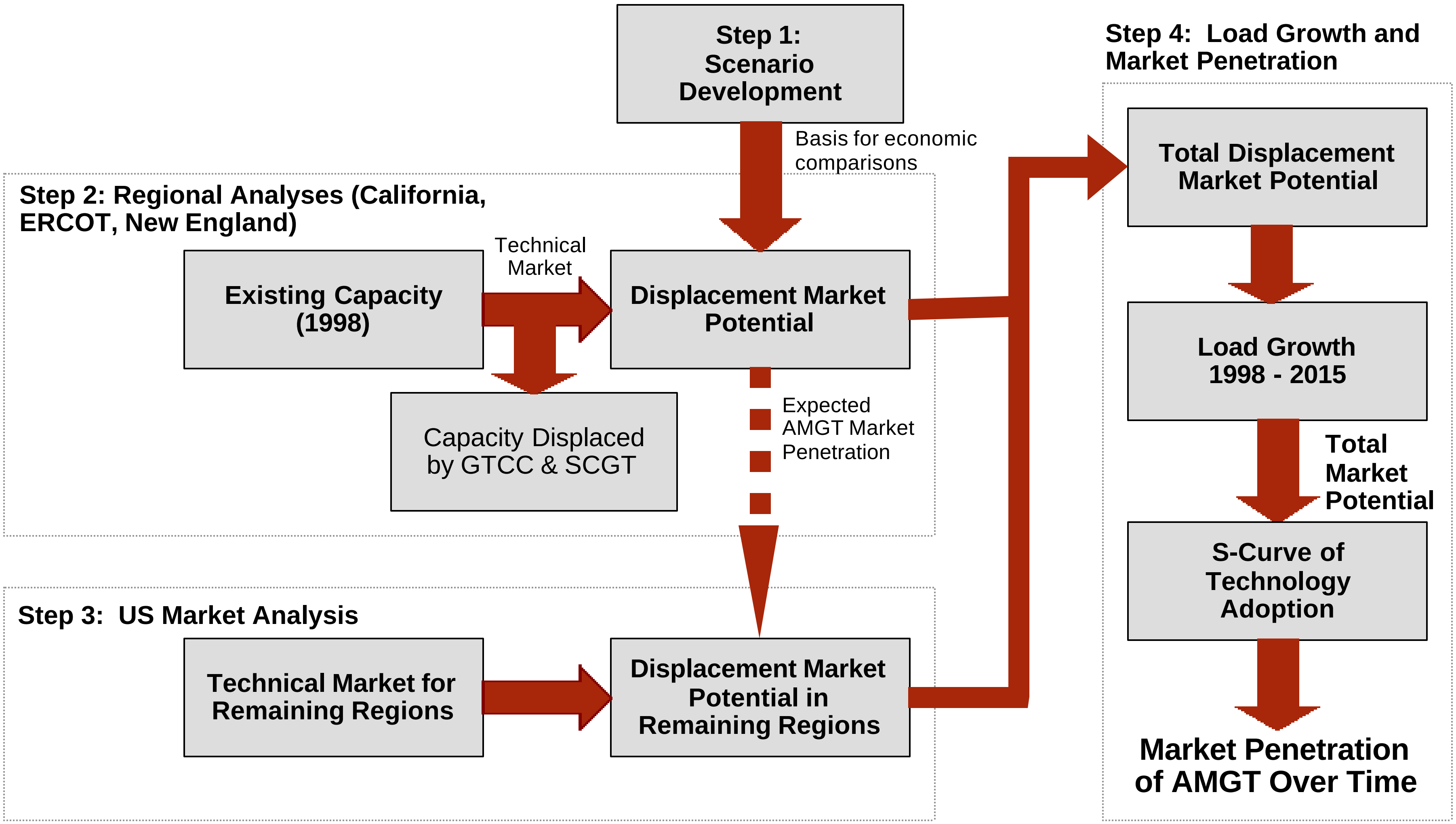
Based on initial market estimates and public benefits potential, the most attractive markets for AMGT technology are intermediate load and cogen applications.

	Market Size	Public Benefit per MW	Overall Public Benefit	Rationale for per MW Benefits*
Intermediate	●	◒	●	Medium efficiency improvements at intermediate capacity factor
Peaking	○	○	○	Large efficiency improvement but at low capacity factor
Repowering	○	◒	◒	Small efficiency improvement at high capacity factor
Ancillary Services	○	◒	◒	Medium efficiency improvement at low capacity factor. May reduce overall reserve margin needs.
Cogen	◒	●	●	Potentially large increase in efficiency at high capacity factor
Green Power	○	●	◒	Benefits of enabling renewable energy

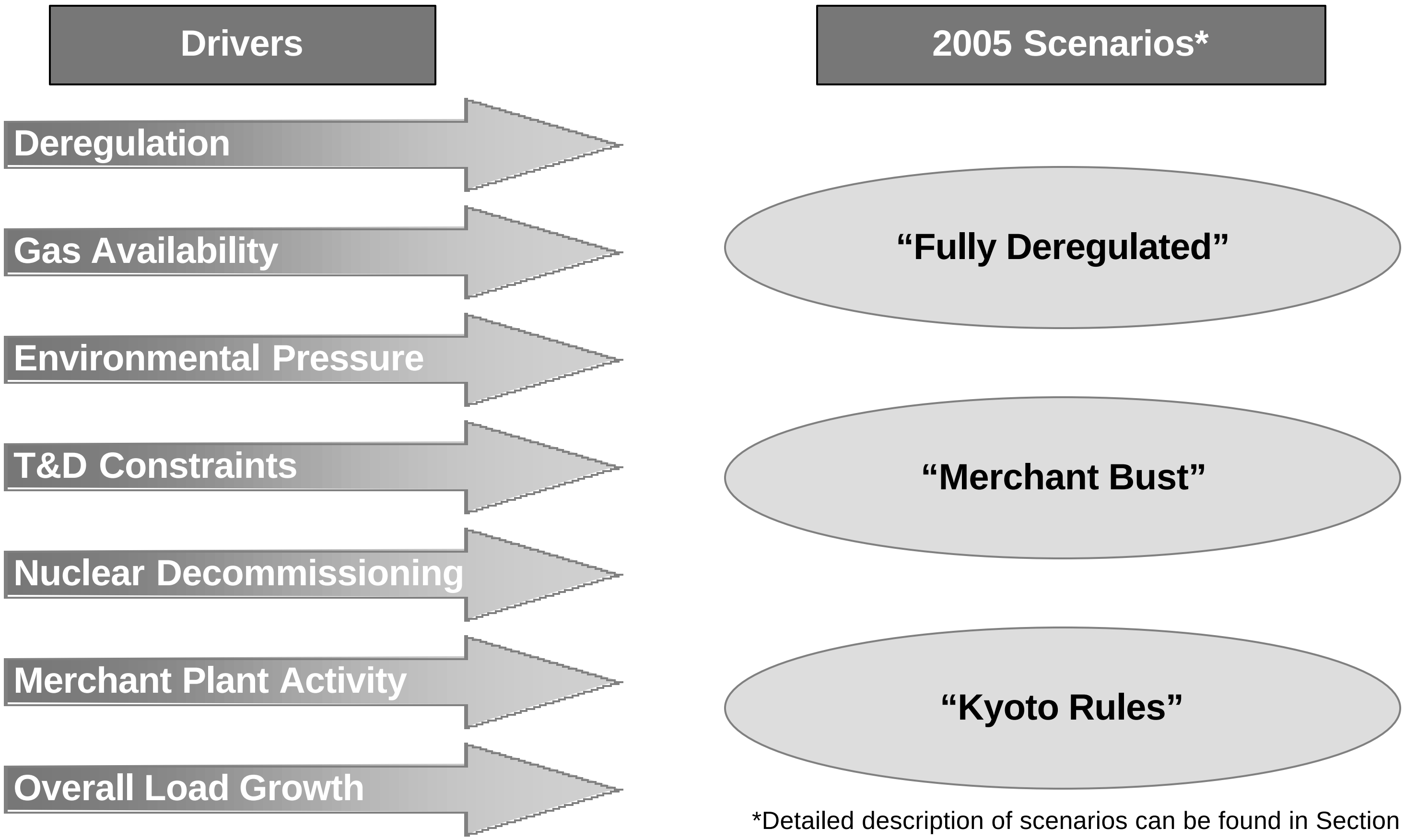
* Public benefits relating to energy savings and costs and environmental aspects are heavily dependent on the applications' capacity factor and the improvement in efficiency that the AMGT can provide in that particular application. Large efficiency improvement: >20%, medium efficiency improvement: 10-20%, small efficiency improvement: <10%

High ● ◒ ○ Low

A four-step approach was used to analyze the intermediate load market.



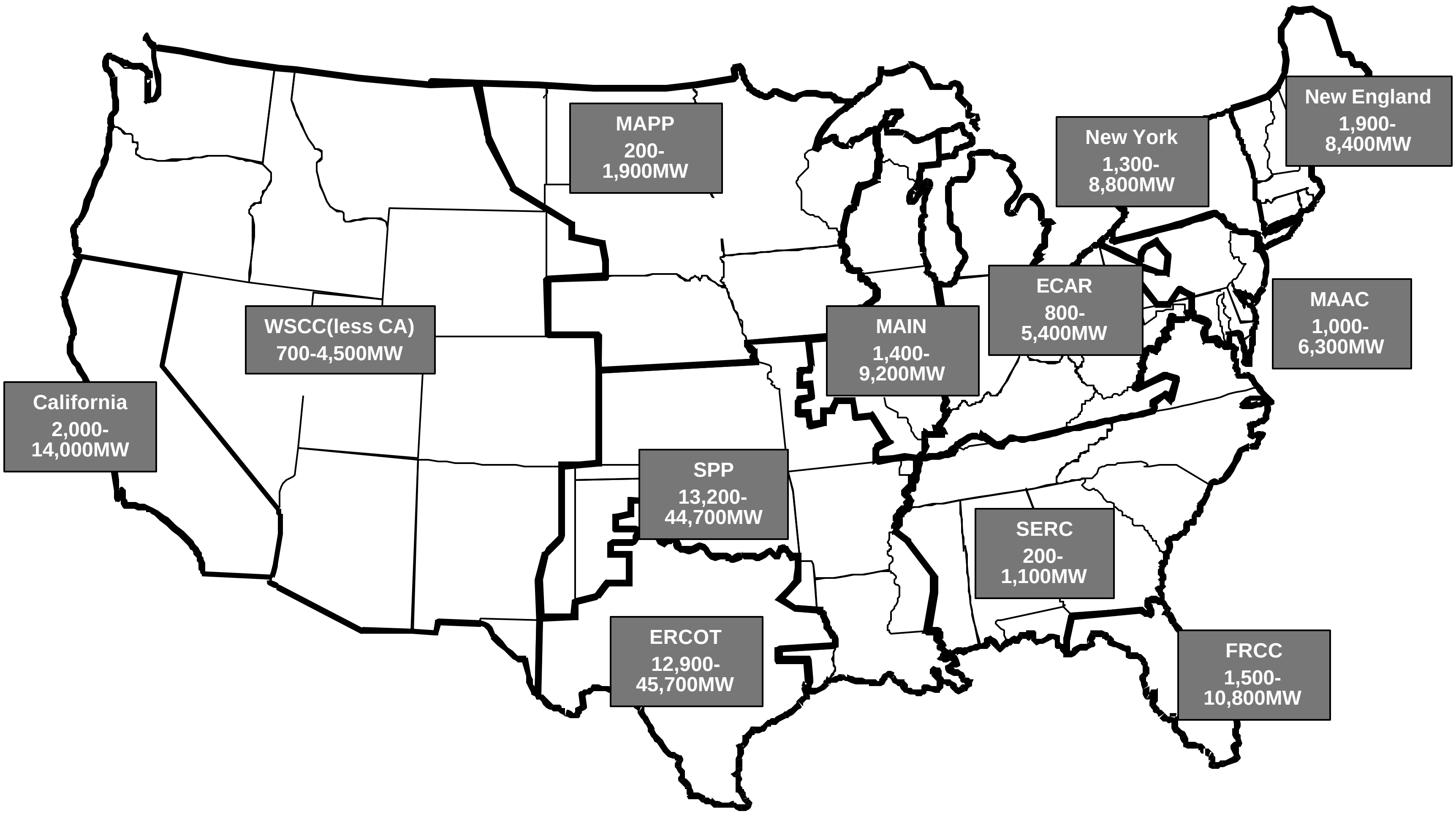
Although intermediate load appears to be an attractive market for AMGT technology, products using this technology will not be commercially available until 2004–2006.



*Detailed description of scenarios can be found in Section 4

Therefore, future scenarios based on key market drivers were used to examine the market potential for AMGT technology in the 2005–2015 timeframe.

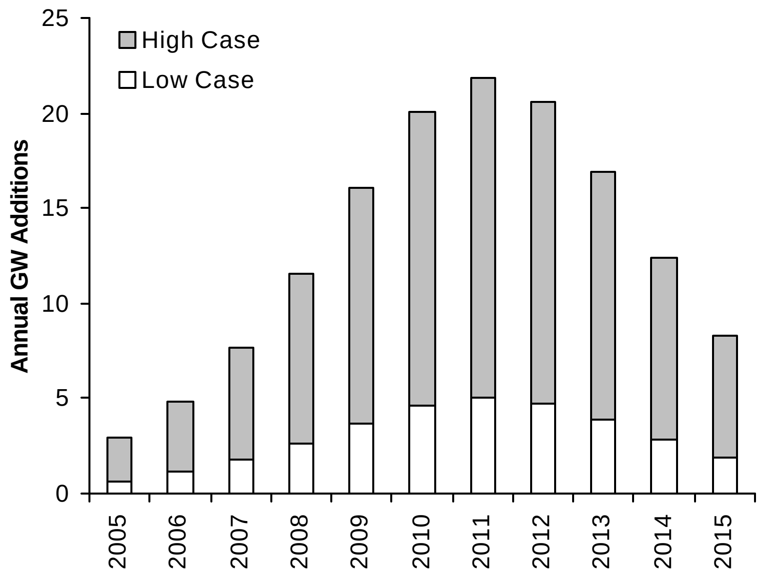
The overall load growth and displacement market potential for AMGT is between 37,000 and 160,000 MW in the 2005–2015 timeframe.



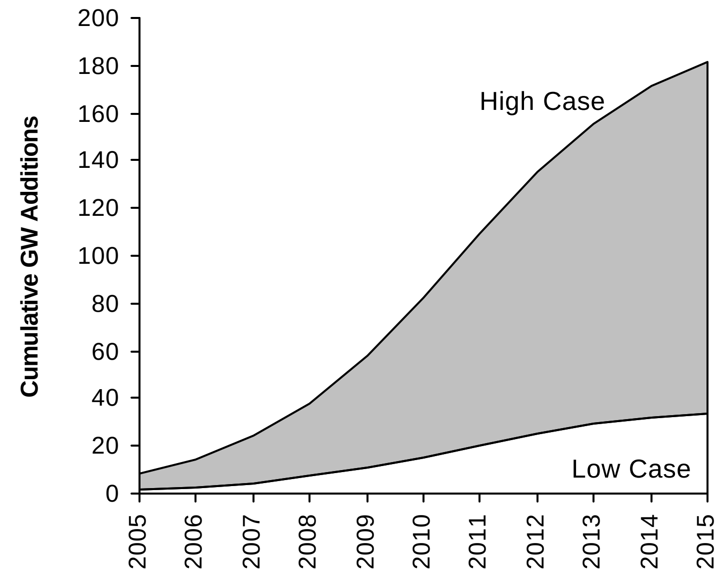
The variation in market potential is driven by the range of assumptions in the future market scenario.

However, there will be a delay in getting the new technology accepted by the market place.

Annual AMGT Additions

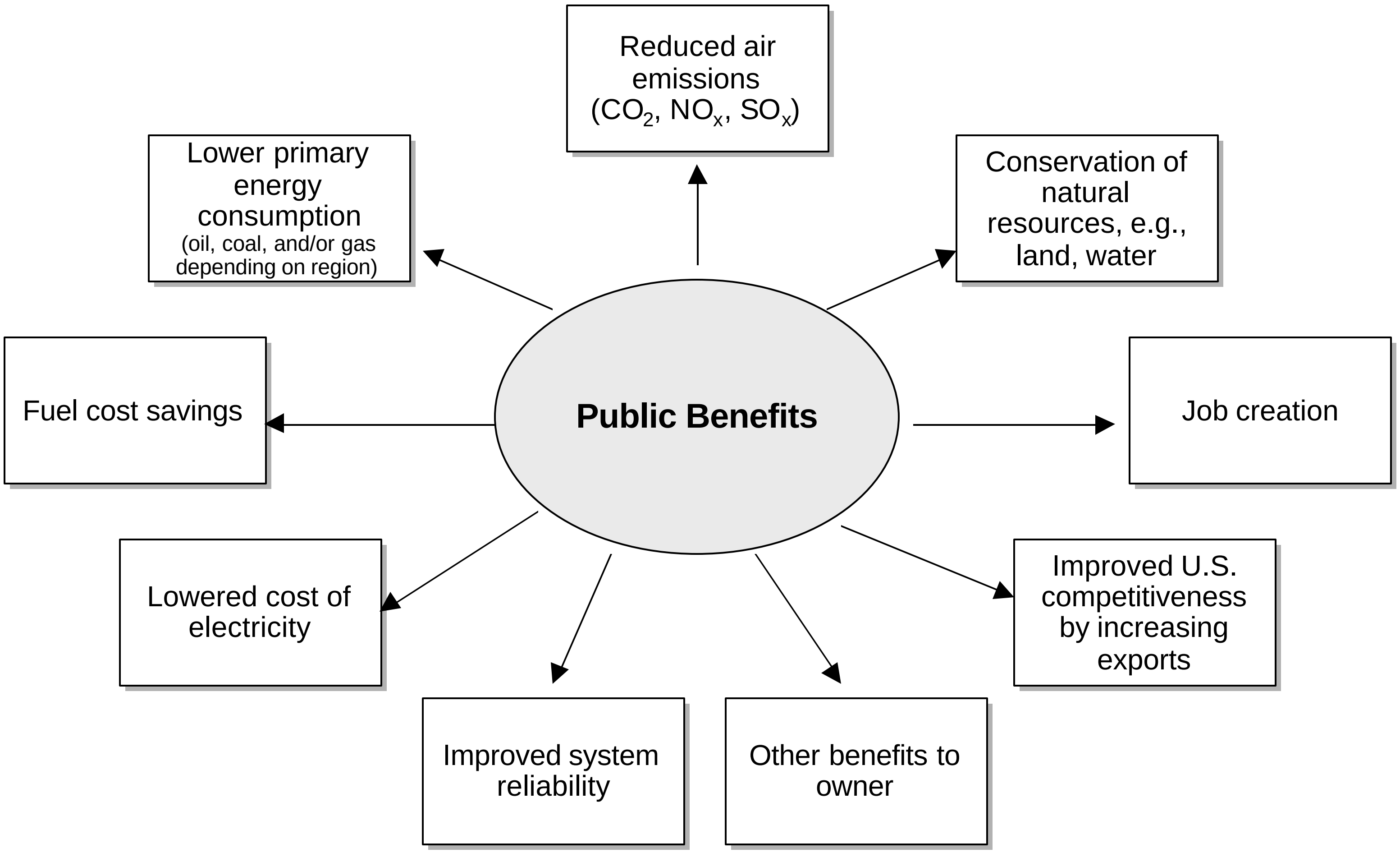


Cumulative AMGT Additions



The annual AMGT addition is projected to peak approximately eight years after commercial product introduction.

The adoption of AMGT technology will lead to public benefits.



The cumulative energy and emissions savings could be substantial especially in the later years when AMGT becomes widely adopted.

	Cumulative Savings in the US		
	2005	**2010**	**2015**
Primary Energy (Trillion BTU)	40	1,100	4,900
Fuel Costs Savings (MM 1996$)	63	1,600	6,900
CO_2 (MMTons)	4.5	120	490
SO_x (MMTons)	0.005	0.13	0.55
NO_x (MMTons)	0.01	0.27	1.1

		Gas Turbine*	**Steam Plant^**	**Percent Reduction**
Land (acres)		5–15	25–45	60% - 90%
Water	Service & Plant Water (mgd)	1–2	0.5–1	
	Cooling Tower Makeup Water (mgd)	0–8	12–15	
	Waste Water Discharge (mgd)	1–8	8–14	
	Overall (mgd)	2–18	20 - 30	30% - 90%

*: Includes SCGT and CCGT (100MW -250MW) .
^: Gas, oil and coal (180MW-225).

In addition, the use of gas turbines will also lead to land and water resources savings from the steam plants they displace.

There appears to be an attractive market for AMGT, however, equipment manufacturers see considerable technical and market risks in developing such a product at this time.

- The very aggressive performance targets of the AMGT make it attractive in intermediate load applications.
- Some equipment manufacturers have expressed reservations regarding the ability of the AMGT to meet the technology performance goals of 50% LHV efficiency at $250/kW.
- Equipment manufacturers also see market risks associated with the evolving electricity market. It will take time (6–10 years) to develop the technology and the product. During this time, the electric utility industry will continue to evolve. Most equipment manufacturers feel uncertain as to what end-state the industry will reach.
- In addition, the technology will have to be accepted by the marketplace at a time when the method by which new technologies are introduced is not clearly understood.
- The risk aversion of manufacturers may be balanced by the future owners of the AMGT.

Manufacturers agree government funding would be required to develop an AMGT product to mitigate technical and market risks.

- Although intermediate load application appears attractive and current technologies (GTCC and SCGT) will not satisfy this market need effectively, most gas turbine manufacturers are reluctant to develop new products on their own.
- Most manufacturers agreed the aggregate performance goals of the AMGT were formidable but attainable. There would be significant technical development that would required and associated technology risk. To achieve these goals in a product would require a large investment and commitment on the part of the government and industry.
- While most agreed there was significant technical and market risk, there was disagreement amongst manufacturers on the need for a program and how the program might be structured.

However, some were hesitant to recommend a large demonstration program.

A technology development program is an attractive option in light of the market uncertainties and the lack of unified support for a product development program from gas turbine manufacturers.

- Two major options exist for supporting development of new power generation systems:
  - Technology Development Program—program in which manufacturers commit to a product vision rather than a product launch
  - Product Development Program—multiphase program in which manufacturers propose specific products
- Technology Developments Program offer several key benefits that would be attractive for this current market environment:
  - Programs offer more flexibility for balancing market uncertainties and potential public benefits
  - Underlying technology developments and RD&D efforts would continue such that they would be available for commercialization when uncertainties diminish
  - Program can benefit both current and future products
- Core engine technology development programs have been used effectively for military aircraft engine development.

Table of Contents

Recent trends in the electric utility industry have heightened the interest in an advanced technology, mid-sized gas turbine product.

- Interest has been evident in recent meetings, workshops, and projects involving the Department of Energy (DOE), California Energy Commission (CEC), CAGT, EPRI, GRI, the US Navy, municipal utilities, and the Gas Turbine Association (GTA).
- While the interest is significant, the specific market needs have not been clearly identified or quantified.
- Furthermore, the benefits that this technology would provide in terms of energy conservation, economic savings and environmental improvements were not currently well understood.
- If a turbine manufacturer was to develop a new product for this market, it could require an investment well in excess of $100 million.
  - Without some specific incentives to reduce risk, none of the major turbine manufacturers appear willing to pursue this product on their own.

DOE is considering what its role should be in developing a new, mid-sized gas turbine product.

- In order to formulate appropriate options for advancing mid-sized gas turbine technology, the specific market needs that the technology will serve need to be more fully understood.
- In order for DOE to support an initiative in this area, there is also a need to quantify the benefits of this technology more specifically.
- Finally, there is a need to determine what the role of DOE should be in facilitating the development of this technology.
- There is synergy between the issues DOE is facing and CEC's interest in the intermediate load capacity in California. The majority of gas steam plants that serve the intermediate load in California is greater than 20 years old, has recently changed ownership, and could be a target for the AMGT technology.

The CEC would also like to better understand these issues, particularly how it impacts California.

ADL performed an issues analysis to organize the key questions DOE is likely to have regarding a mid-sized gas turbine program.

Should DOE launch a program initiative to address mid-sized gas turbine technology development?

Is there a significant market need for an advanced technology, mid-sized, gas turbine?

- How large is the market opportunity in the US?
- What is the precise nature of the market needs?
- How does the market opportunity vary by region within the US?
- How will deregulation impact the opportunities or benefits?
- How would introduction of this product impact the ATS market?

Are there significant benefits to the United States from the development of mid-sized GT technology?

- What are the environmental benefits?
- What are the economic benefits?
- What other benefits might result from this technology?
- How do these benefits fit with the benefits associated with the ATS program?

Are there viable technology options that will meet the needs that have been identified in this area?

- What are the technology development needs associated with pursuing the preferred technology options?
- Are there logical technology development steps involved in the development and deployment of a new product?
- Is there an appropriate government role in facilitating the development of this technology?

Are there other policy options that the DOE/FETC could employ to encourage development of mid-sized gas turbine technology?

- Should the government encourage the early replacement of inefficient power plants by offering other incentives?
- Should the government encourage equipment manufacturers to develop the products that will meet these needs by providing incentives other than direct funding of new technology?

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- The report does not attempt to define the technology that will achieve these characteristics.
- The main objectives of the study were the following:
  - Identify and screen applications for AMGT technology
  - Estimate the market potential for AMGT in intermediate load application
  - Estimate the public benefits that would result from the adoption of AMGT in intermediate applications
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Table of Contents

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	Transmission Congestion
Cogen*	High T/E Ratio
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Green Power*	Dedicated Biomass
	Cycle Hybrid
	Project Integration

*See Appendix A for definitions

Based on estimated technical market potential, there appears to be attractive markets for these six application classes, particularly intermediate load.

	Estimated Technical Market* Potential (GW)	Comments/Data Source
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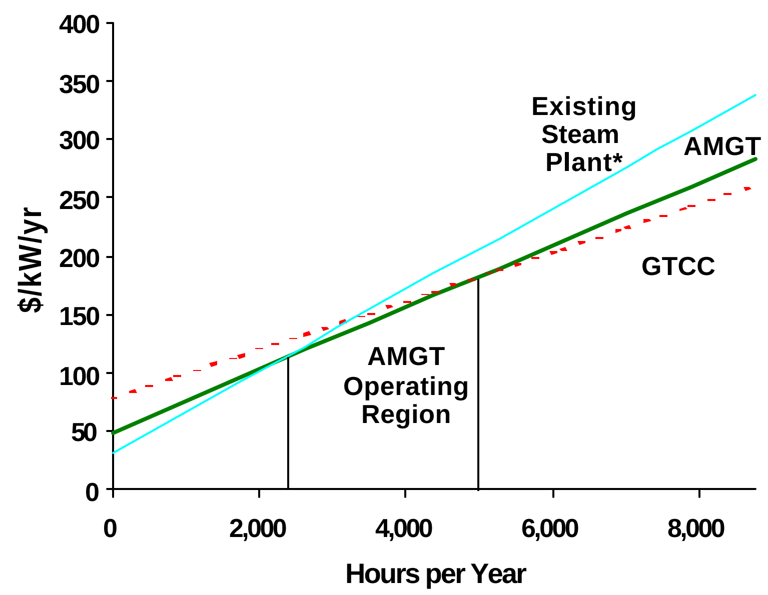
Note: These market numbers are not necessarily additive.

Technical market potential estimates were obtained from previous studies and verified using other independent sources.

The AMGT's capital cost and efficiency make it suited to displace current intermediate load capacity.

- The current intermediate load capacity in the US is predominantly fossil-steam plants.
- The technology of choice for most new merchant plants is the the GTCC. It is chosen because of its low capital costs, high efficiency and short construction times.
- These GTCC plants are being developed and installed with the expectation that they will operate as close to baseload as possible.
- When these plants come on line they will force the intermediate load steam plants to operate at lower and lower capacity factors.
- There is a limit (3,500 hrs), however, below which GTCC cannot displace these steam plants.
- Its capital cost and efficiency allow the AMGT to be the most economical option from 2,200 to 5,000 hours per year.

Technology Screening Curve



*Estimated based on steam plants operating in intermediate load duty (20%-30% capacity factor) in California.

New GTCC merchant plants are unlikely to completely displace existing steam plant capacity that is currently operating in intermediate load duty.

Intermediate load and cogen applications would appear to offer the largest overall public benefits.

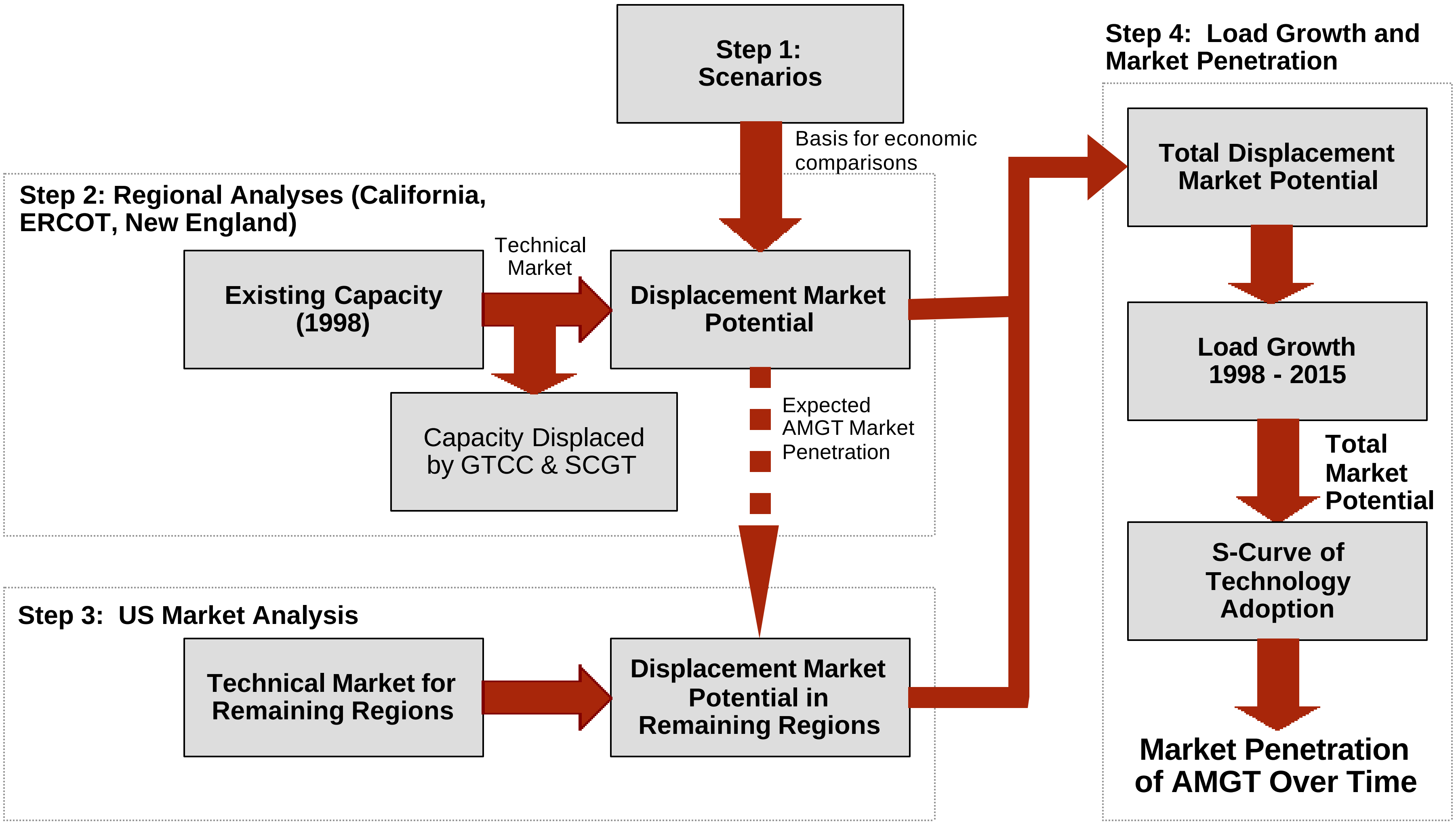
	Market Size	Public Benefit per MW	Overall Public Benefit	Rationale for per MW Benefits*
Intermediate	●	◓	●	Medium efficiency improvements at intermediate capacity factor
Peaking	○	○	○	Large efficiency improvement but at low capacity factor
Repowering	○	◓	◓	Small efficiency improvement at high capacity factor
Ancillary Services	○	◓	◓	Medium efficiency improvement at low capacity factor. May reduce overall reserve margin needs.
Cogen	◓	●	●	Potentially large increase in efficiency at high capacity factor
Green Power	○	●	◓	Benefits of enabling renewable energy

* Public benefits relating to energy savings and costs and environmental aspects are heavily dependent on the applications' capacity factor and the improvement in efficiency that the AMGT can provide in that particular application. Large efficiency improvement: >20%, medium efficiency improvement: 10-20%, small efficiency improvement: <10%

High ● ◓ ○ Low

Table of Contents

A four-step approach was used to analyze the intermediate load market.



A four-step approach was used to analyze the market.

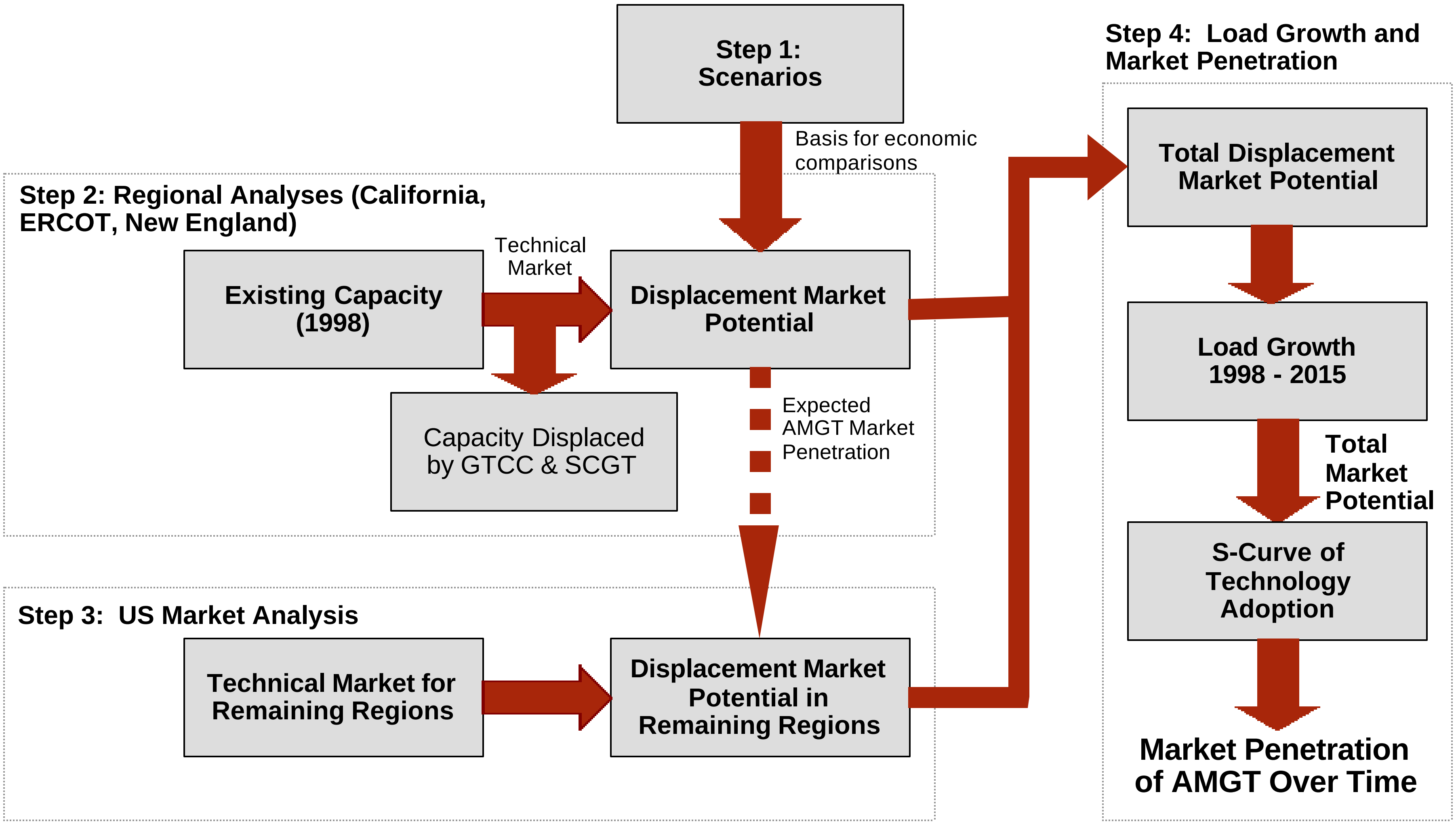
Step 1: **Scenarios.** Scenarios were developed to gauge the technical market potential and the basis for economic comparison of the AMGT vs. competing technology. Two scenarios were selected to represent the most optimistic and pessimistic scenarios for the AMGT.

Step 2: **Regional Analysis.** The displacement market potential is developed by examining the marginal costs of existing facilities in three regions (CA, ERCOT, and New England). These facilities are first compared to SCGT and GTCC on an economic basis to determine how much existing capacity will be displaced by improved SCGT and GTCC technology. This point in the analysis describes what happens if the AMGT technology is not developed and commercialized. This new mix of capacity is then compared to the AMGT on an economic basis to determine how much AMGT could be added to displace this new capacity mix.

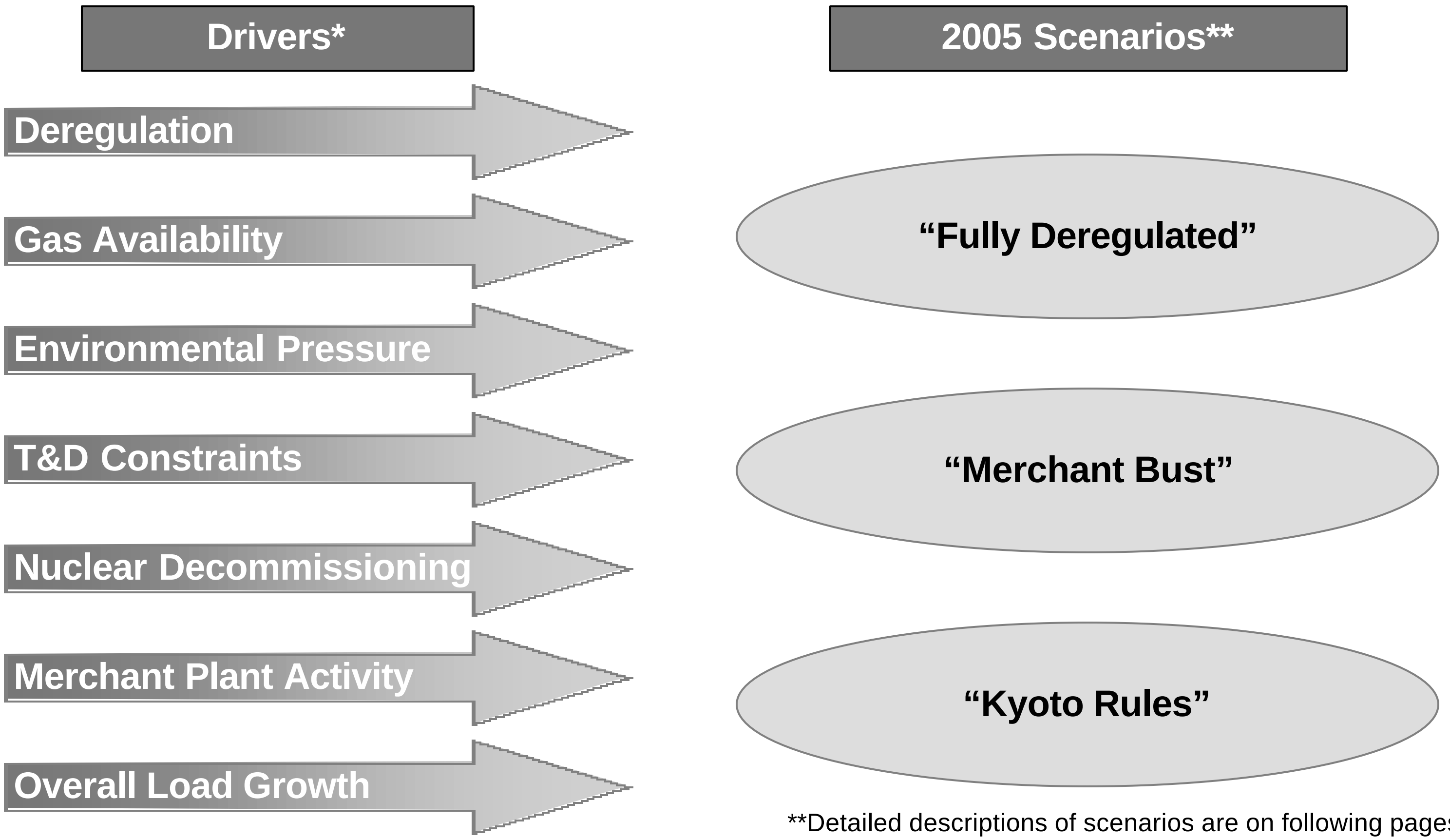
Step 3: **US Market Analysis.** To determine the AMGT displacement potential in the remaining regions, the technical market potential is first determined in those regions. The analysis for the three regions in Step 2, represents three ranges of expected AMGT market penetration (high, medium, and low). The expected penetration of AMGT in remaining regions is characterized based on fuel mix. For example, since SPP's intermediate load capacity is 98% gas, it's expected AMGT penetration will be similar to ERCOT. New York and FRCC with a more heterogeneous fuel mix will have a market penetration more like New England.

Step 4: **Load Growth and Market Penetration.** Load growth is added to the total displacement market by using NERC's projections for load growth. An S-curve is applied to the displacement and growth markets to determine the market penetration over time.

The first step in the analysis was to develop scenarios to bracket the analysis results and to provide a basis for economic comparison.



Since AMGT products will not be commercially available until 2004–2006, future scenarios based on key market drivers were developed for the 2005–2015 timeframe.



**Detailed descriptions of scenarios are on following pages.

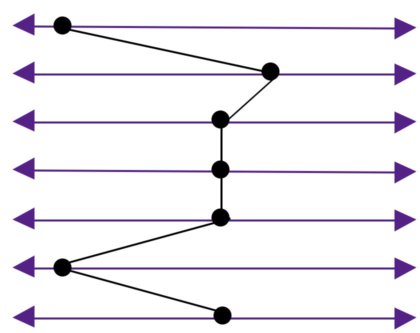
*See Appendix B for explanations of drivers

The "Fully Deregulated" Scenario is the least attractive for the AMGT because of the high penetration of GTCC.

"Fully Deregulated" Scenario

- The year is 2005 and the entire U.S. is opened to pool-based competition.
- The latest ATS GTCC technology (61% efficient, single-shaft, steam-cooled units optimized for baseload operation) now drives the pool price for baseload capacity.
- Marginal baseload units (including early-to-mid 1990s GTCCs that are about 51% efficient) have been pushed into intermediate-load operation, closing many of the pre-1990 low-efficiency, intermediate steam units. SCGT plants have also been built for the intermediate load market.
- Merchant plant development is highly active with most new capacity built to operate in this fashion, and several GTCC projects vying to enter the market each time a nuclear unit closes.
- Merchant power developers are not willing to take big technology risks but see some advantage in advanced technology.
- With high gas availability, stable gas prices and steady equipment costs, GTCC is still the technology of choice for merchant plants.
- AMGT competes on price with older vintage GTCC and the relatively high-efficiency steam capacity that remains.
- The value of ancillary services has declined as the market matured.

Market Driver	Impact	2005 End-State		Impact
Deregulation	+	*Nation-wide*	*Partial*	+++
Gas Availability	—	*Low*	*High*	++
Environmental Pressure	—	*Light Green*	*Dark Green*	++
T&D Constraints	0	*Light*	*Heavy*	+
Nuclear Decommissioning	0	*Delayed*	*Accelerated*	+
Merchant Plant Development Activity	+	*Sustained*	*Stalled*	++
Overall Load Growth	0	*Low*	*High*	+

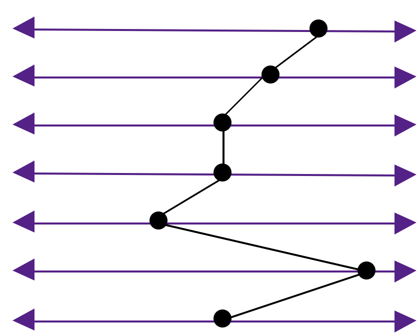


The "Merchant Bust" Scenario would provide the greatest opportunity for the AMGT.

"Merchant Bust" Scenario

- GTCC capacity is overbuilt between 1998 and 2002. Some of the GTCC units are forced to run in as intermediate units and lose money.
- It takes several years for investors to regain confidence in merchant power development. Plant developers have abandoned the US market and are focusing on Asia where economies are seeing a strong recovery after the collapse in the late 1990s.
- The failure of merchant plants has caused some states to abandon or slow deregulation efforts. Other states are making the permitting process more difficult.
- In 2005, much of the inefficient intermediate steam capacity outside of New England is still on-line.
- AMGT is highly competitive with intermediate steam units and is timed and sized right for new but cautious merchant activity.
- Monopoly utilities are responsible for the majority of the new capacity.

Market Driver	Impact	2005 End-State		Impact
Deregulation	+	*Nation-wide*	*Partial*	+++
Gas Availability	—	*Low*	*High*	++
Environmental Pressure	—	*Light Green*	*Dark Green*	++
T&D Constraints	0	*Light*	*Heavy*	+
Nuclear Decommissioning	0	*Delayed*	*Accelerated*	+
Merchant Plant Development Activity	+	*Sustained*	*Stalled*	++
Overall Load Growth	0	*Low*	*High*	+

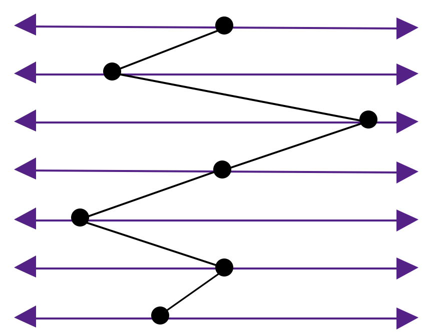


The "Kyoto Rules" Scenario would be neutral to the AMGT overall.

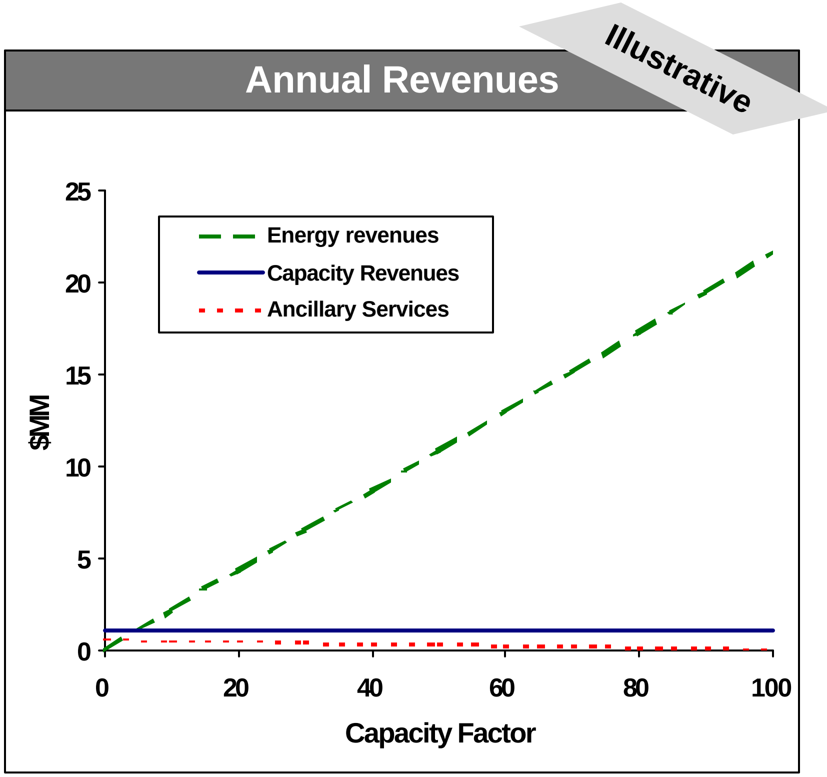
"Kyoto Rules" Scenario

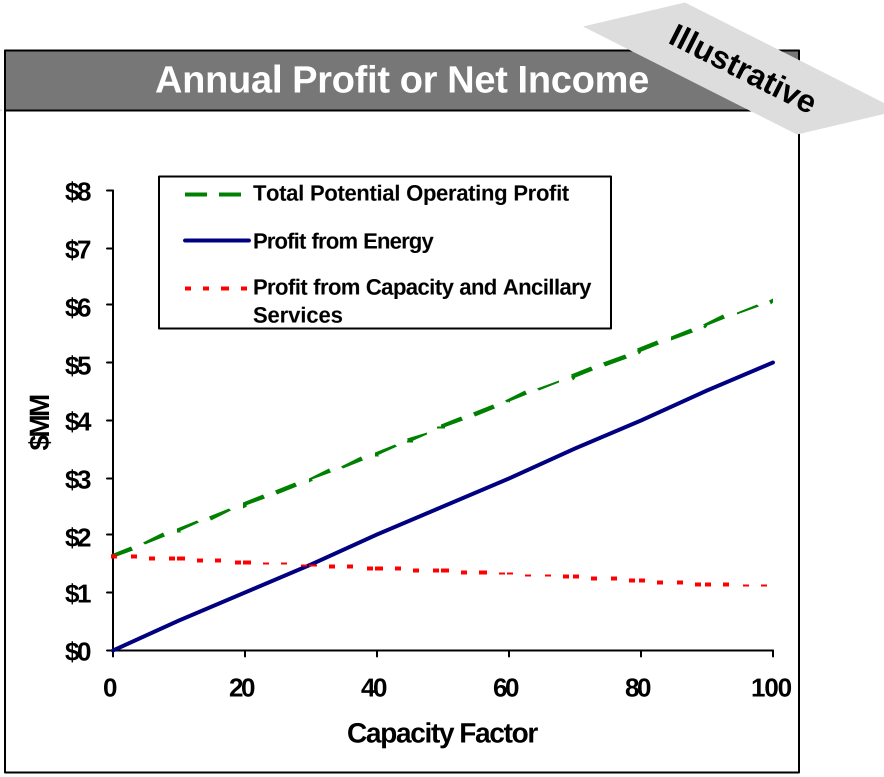
- The year is 2005 and global warming is the number one issue in public opinion polls after rising sea-levels flooded parts of Florida. The newly elected president intends to follow through on his campaign promise to deal with this situation.
- CO_2 reductions are the prime policy concern of the U.S., and there is an ever-reducing number of tradable emissions permits.
- Nuclear decommissioning has been delayed to keep CO_2 emissions down.
- The regulatory landscape is a patchwork of retail access as some states have slowed deregulation progress to better deal with the environmental crisis.
- Due to the cost of CO_2 permits, all new baseload capacity is GTCC.
- Developers are willing to take more technology risk for higher efficiency, and government policy helps to reduce that risk.
- AMGT could push out remaining oil and coal-fired intermediate plants.
- Many state legislatures have enacted or expanded renewable portfolio standards.
- Renewable hybrid option allows AMGT to compete in renewable portfolio market.
- More firming capacity is needed due to intermitancy of increased renewable generation.

Market Driver	Impact	2005 End-State		Impact
Deregulation	++	*Nation-wide*	*Partial*	+++
Gas Availability	—	*Low*	*High*	++
Environmental Pressure	—	*Light Green*	*Dark Green*	++
T&D Constraints	0	*Light*	*Heavy*	+
Nuclear Decommissioning	0	*Delayed*	*Accelerated*	+
Merchant Plant Development Activity	+	*Sustained*	*Stalled*	++
Overall Load Growth	0	*Low*	*High*	+



In the scenarios examined, a power plant could potentially generate revenue from three markets: energy, capacity and ancillary services.





Note: Based on a hypothetical 100 MW plant using market prices experience in PJM and California.

The energy market will account for the majority of an AMGT plant's revenue, but the capacity and ancillary services markets may present an important opportunity for additional revenue.

Of these three markets the energy market is the most mature and forms the basis for this assessment of the AMGT technology market potential.

- Not all regions have or will have a capacity market. The definition of the ancillary services market varies and will continue to vary by region as well. Owners of the AMGT plant will have to decide which markets they will participate in as they may not be able to simultaneously bid into all markets.
- The capacity and ancillary services markets are volatile and are subject to price caps in some regions. While the capacity and ancillary services market will evolve over time, the ultimate value placed on these markets is difficult to forecast.

CA - ISO				
Energy Prices* ($/MWh)	Day Ahead Ancillary Services Capacity Prices^ ($/MW-day)			
	Regulation	Spinning Reserve	Non Spinning Reserve	Replacement Reserve
25.89	23.11	11.27	0.50	0.78
6.80–39.01	4.61–248.50	1.51–200.00	0.09–1.90	0.30–1.99

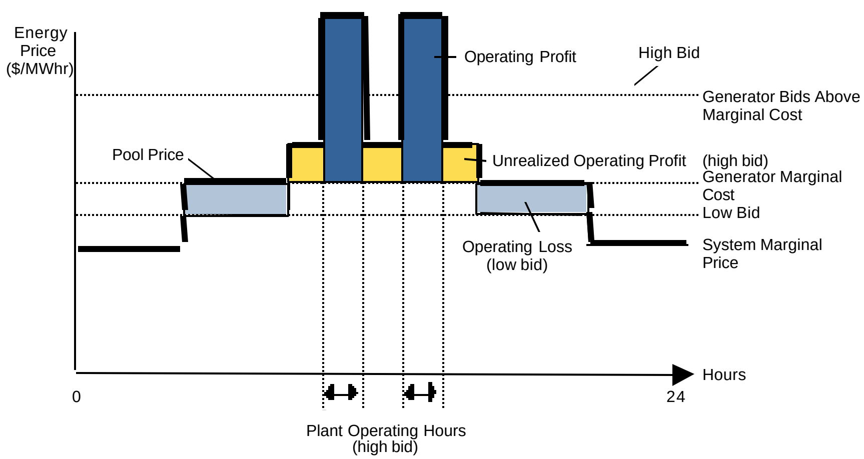
PJM	
	Capacity Credit Market** ($/MW-day)
Average	31.58
Range	5.80–80.94

*: CA ISO January 2-8, 1999 peak hour
**: PJM capacity market clearing price for January-May, 1999
^: CA ISO January 2-8, 1999 peak hour ancillary services at NP15

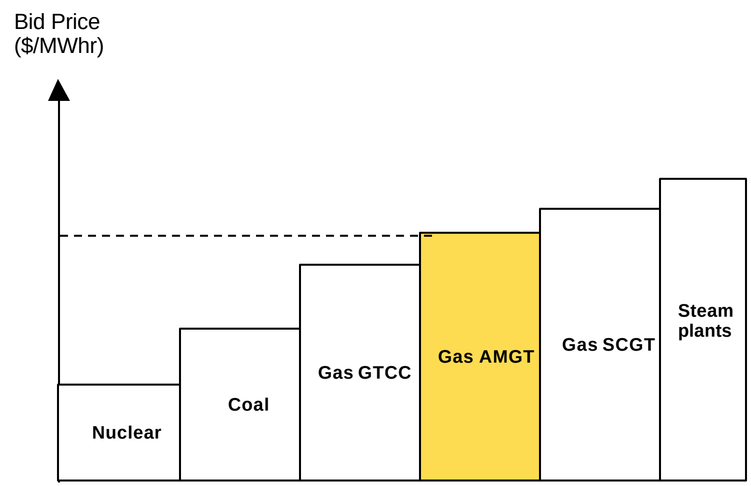
- The market potential for AMGT would likely increase if the potential payments for the capacity credit and ancillary service markets are taken into account.

The economic competitiveness of a power plant in the energy market is based on its marginal cost of energy production.

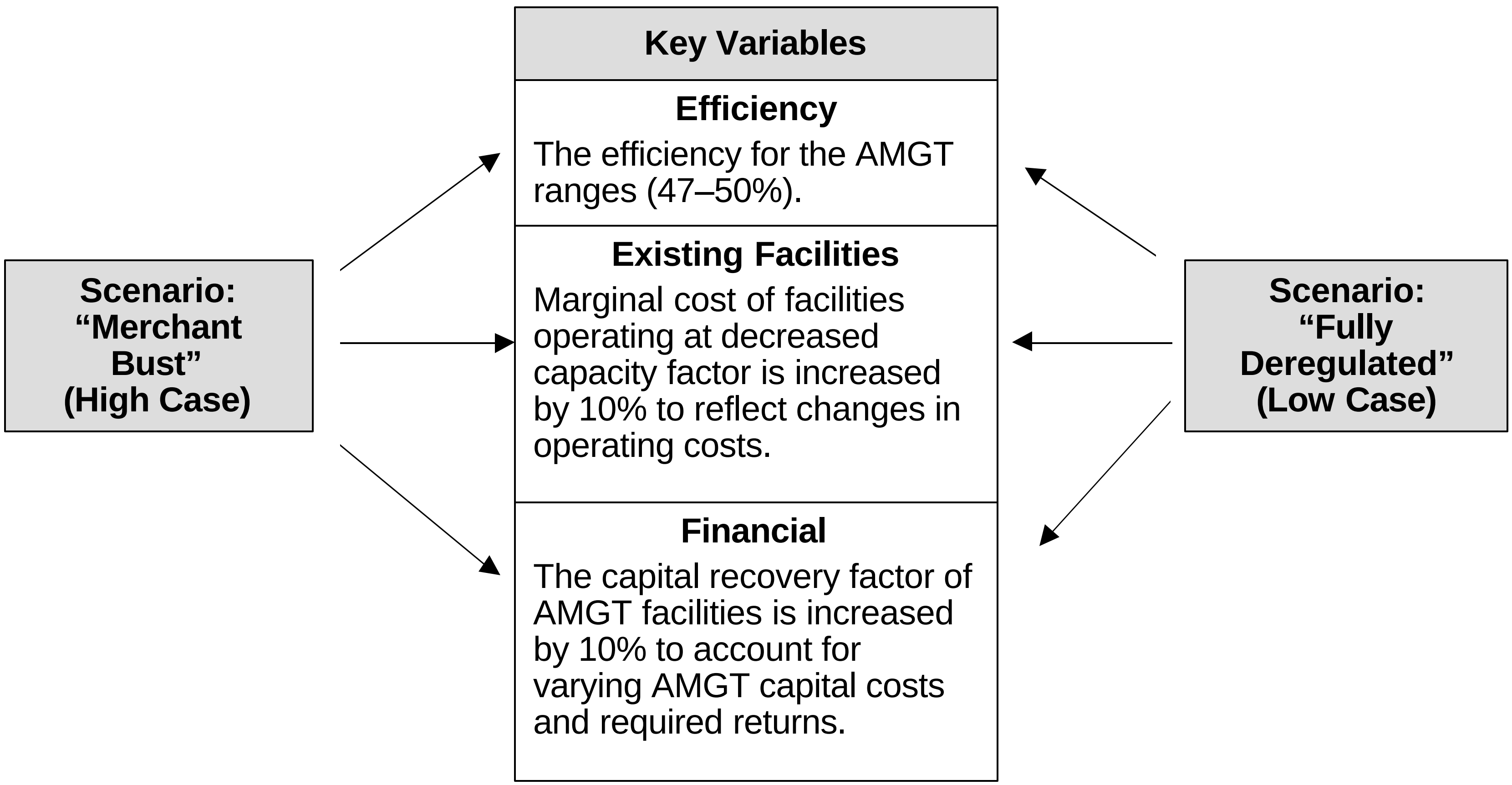
Operating Profit



Ranking of Bid Prices

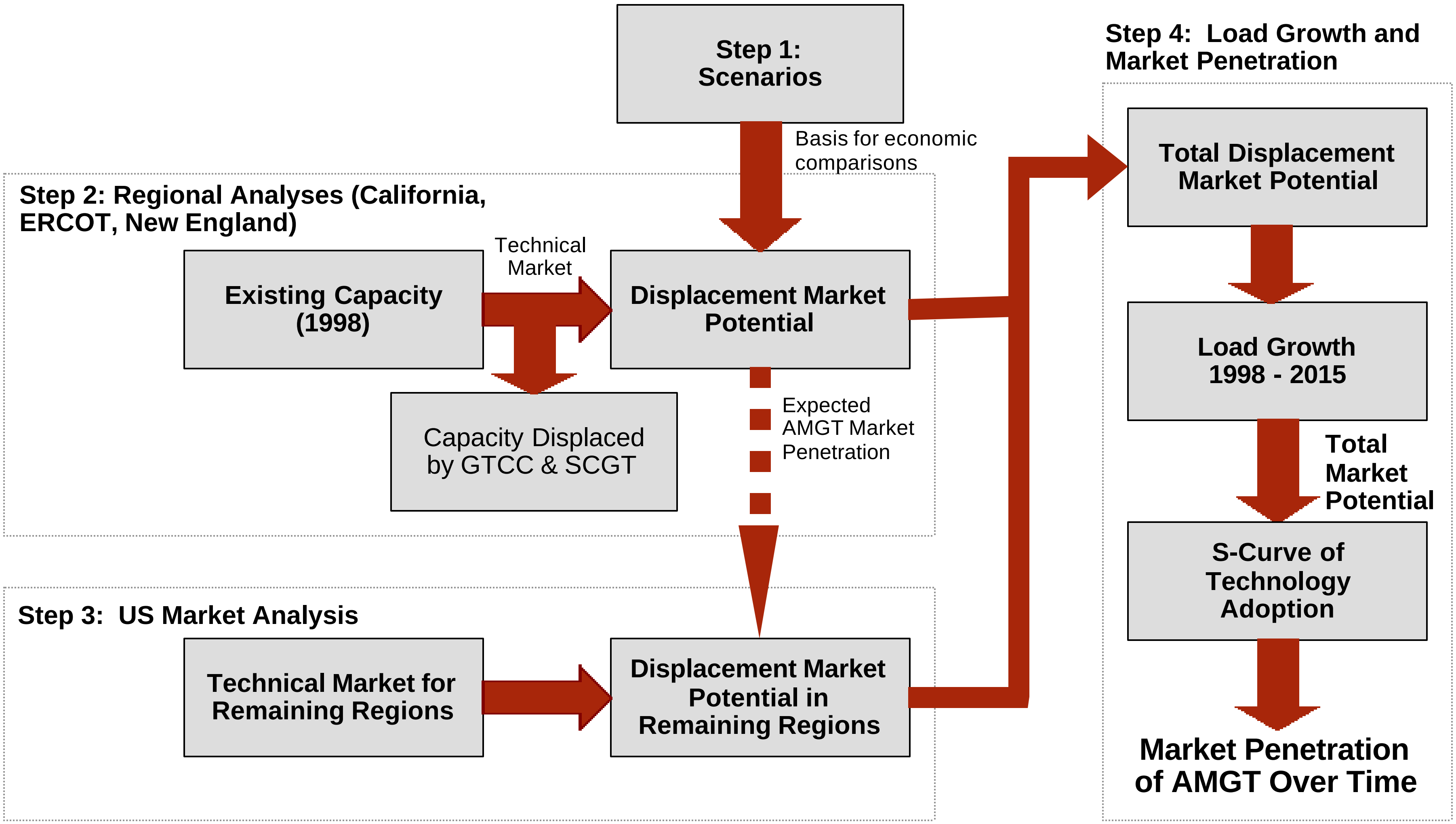


The “Fully Deregulated” and “Merchant Bust” scenarios will bracket the opportunity for the AMGT.



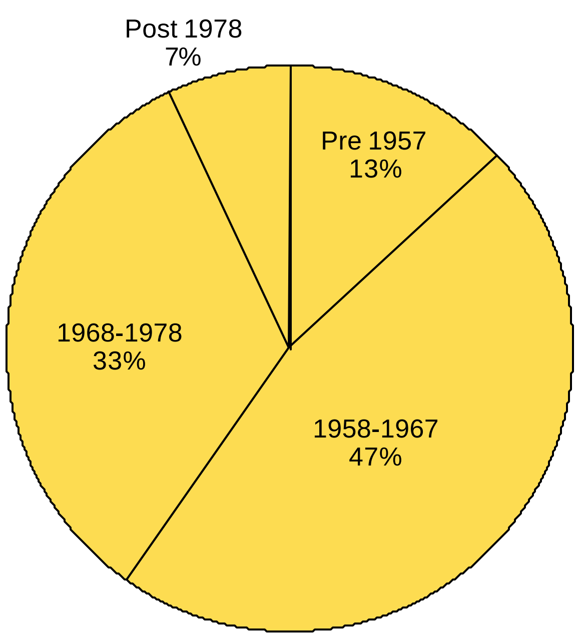
In addition to the uncertainties involving future scenarios, there are other conditions that will influence the AMGT opportunity.

The second step in the analysis is to determine the displacement market potential on a regional basis.



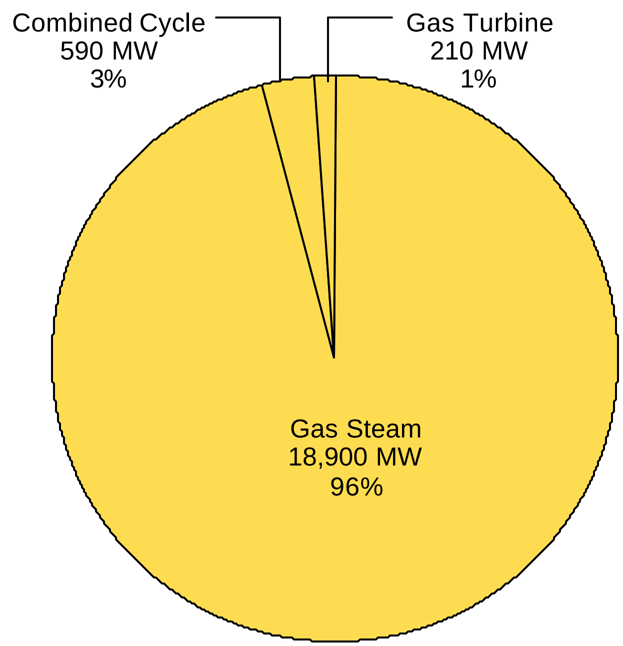
California's intermediate capacity mix is all gas plants, 93% of which are over 20 years old.

Intermediate[1] California Capacity by Age



Total Intermediate Capacity = 19,750 MW

Intermediate[1] California Capacity by Fuel/Technology



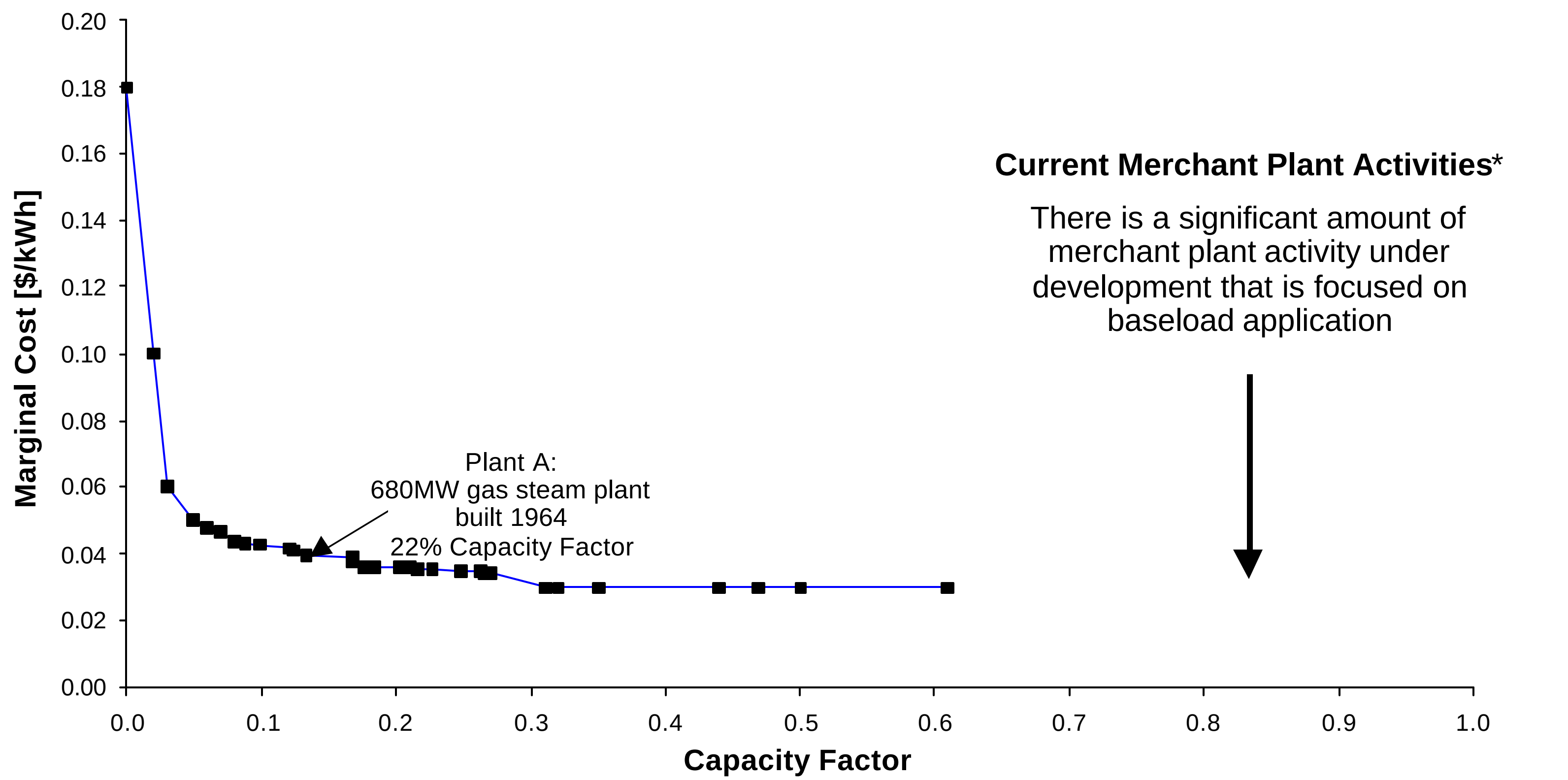
Total Intermediate Capacity = 19,750 MW

1. Intermediate is defined by >6% capacity factor and marginal cost greater than AMGT marginal cost.
   Source: RDI database and ADL analysis

Note: See Appendix C for details

New capacity can be installed in California where it has a lower marginal cost than the existing capacity.

Marginal Cost Versus Capacity Factor for Existing California Facilities

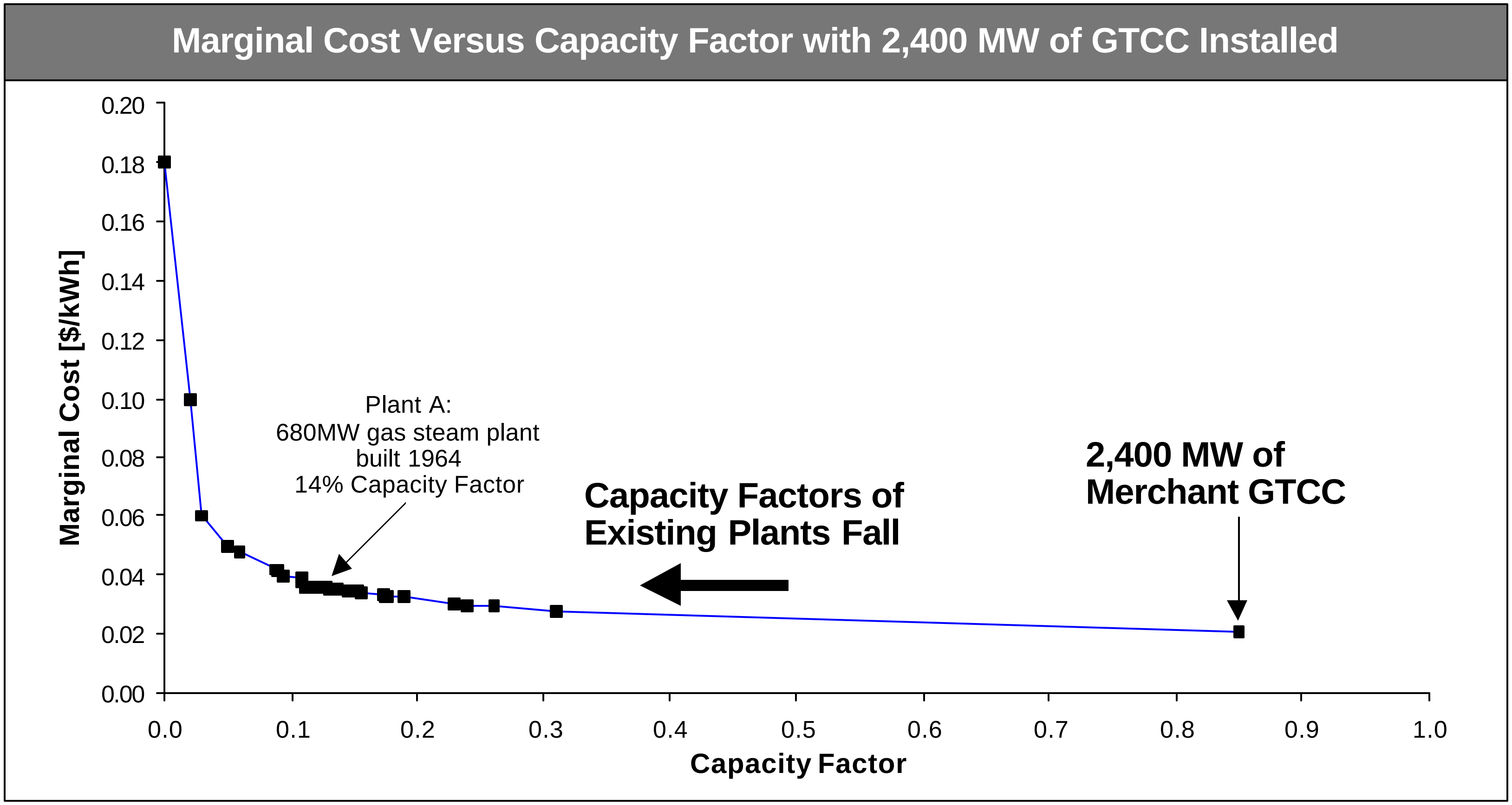


The marginal cost curve will change over time as new merchant plants are brought on line.

Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data. The analysis does not include baseload facilities, such as the nuclear capacities. Source: RDI database and ADL analysis

*See Appendix C for details

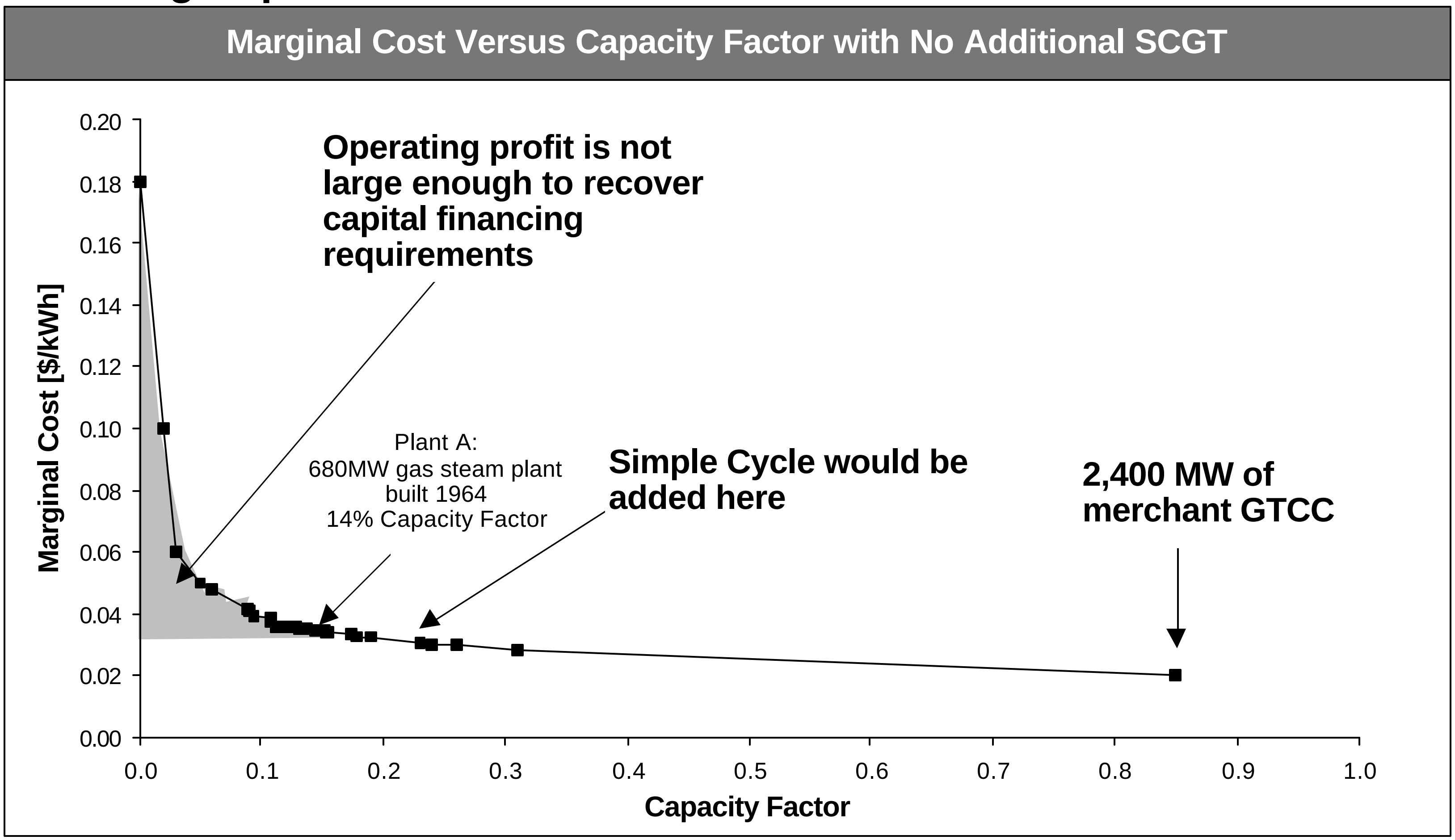
GTCC is added where it has lower than the marginal costs than existing facilities and still recover its capital costs.



In the "Fully Deregulated" scenario, 2,400 MW of new GTCC capacity can be added to the system, reducing the capacity factor of existing plants.

Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
GTCC assumptions: 61% eff (LHV) $500/KW total installed cost

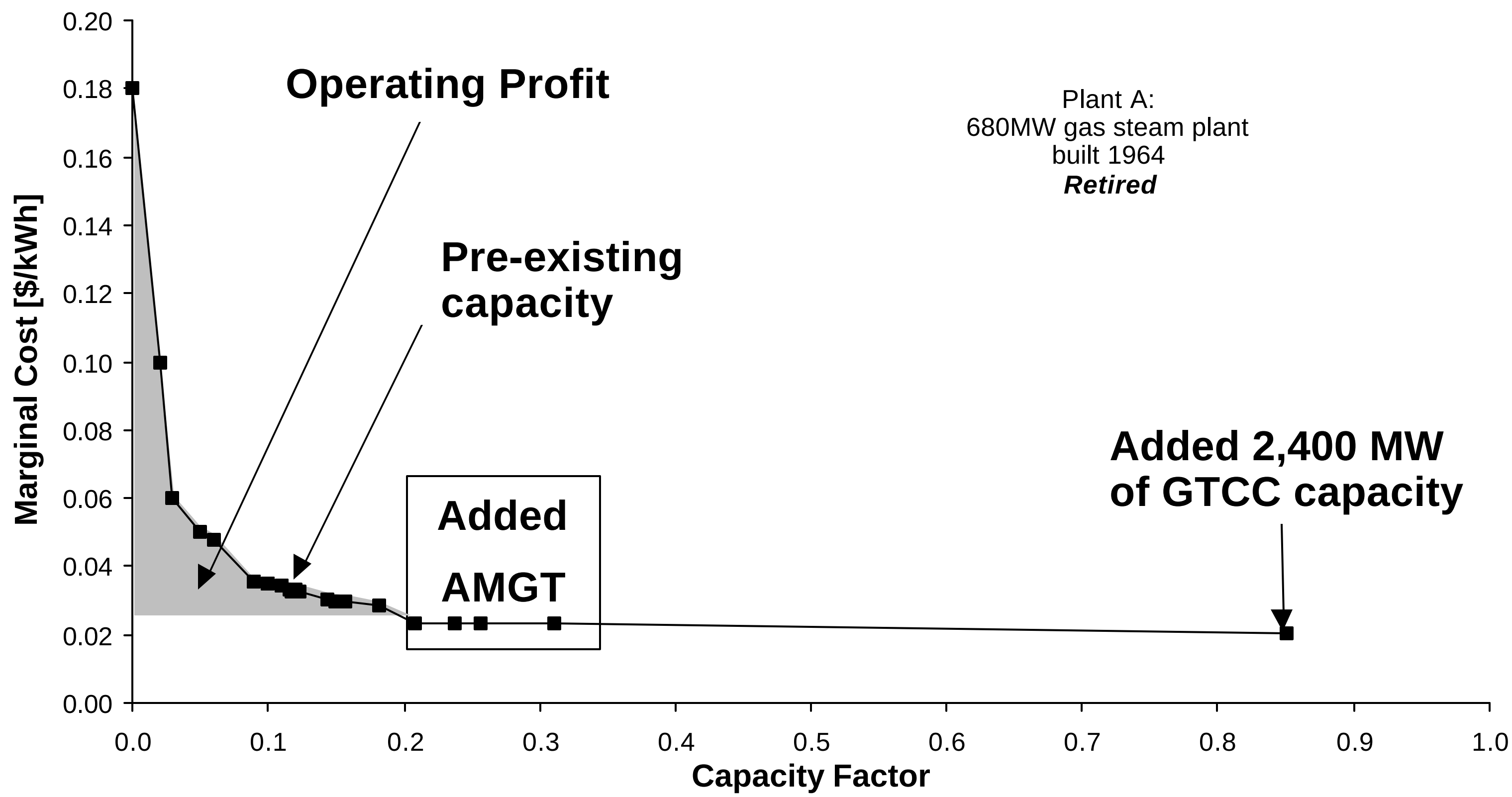
New Simple Cycle units cannot be added to intermediate load duty because its operating profit is not large enough to recover capital financing requirements.



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
SCGT assumptions: 38% eff (LHV) $280/KW total installed cost

In the "Fully Deregulated" scenario, over 5,000 MW of AMGT capacity can be added until the operating profit is unable to recover the capital financing requirements.

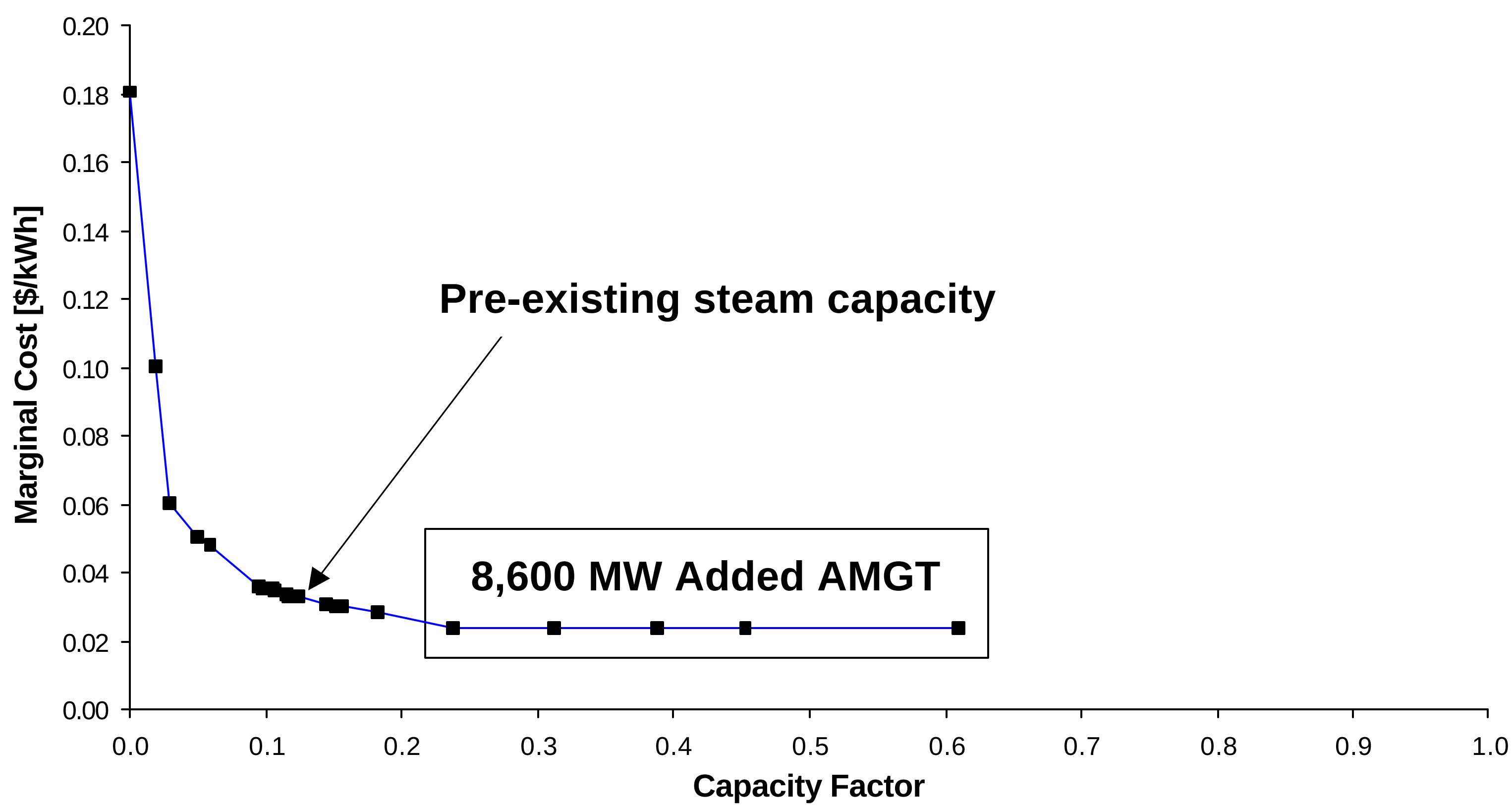
Marginal Cost Versus Capacity Factor with 5,000 MW of AMGT Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC and AMGT.
AMGT assumptions: 50% eff (LHV) $250/KW total installed cost

A similar analysis was performed for the "Merchant Bust" scenario, however in this scenario it was assumed that no GTCC or SCGT is built in California before AMGT is introduced. This would allow for 8,600 MW of AMGT to be installed.

Marginal Cost Versus Capacity Factor after 8,600 MW AMGT Added



Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data. The analysis does not include baseload facilities, such as the nuclear capacities.
Source: RDI database and ADL analysis

A sensitivity analysis was performed for both scenarios. In the "Fully Deregulated" scenario, 1,800–7,100 MW of AMGT could be added to California.

- The sensitivity analysis was performed by varying the marginal cost of existing facilities and the efficiency and capital carrying charge of AMGT.
- **Marginal Cost of Existing Facilities** - Increasing the marginal costs of existing facilities increases the amount of AMGT that can be added.
  - As AMGT is added the capacity factor of existing facilities will decrease.
  - The marginal cost of existing steam facilities can be expected to increase due to increased operating costs and lower efficiency resulting from lower capacity factors and increased cycling.
  - The sensitivity analysis assumes that the addition of AMGT causes a 10% increase in the marginal cost of all facilities that are used less as a result of the AMGT additions.
- **AMGT Efficiency** - Decreasing AMGT efficiency decreases the amount of AMGT that could be added.
- **Capital Carrying Charge -** Increasing the capital carrying charge by 10% significantly decreases the amount of AMGT that can be added in California. This increase in capital carrying charge could be caused by higher capital costs or more stringent financing requirements.
  - A 10% increase in the capital carrying charge would result in a 48% decrease in the AMGT additions in California.

	AMGT Market Potential Sensitivities - California "Fully Deregulated" Scenario		
AMGT Efficiency [LHV]	**"Fully Deregulated" Base Case [MW]**	**10% Increase in Marginal Cost of Existing Facilities [MW]**	**10% Increase in Carrying Charge [MW]**
47%	3,300	5,600	**1,800**
50%	5,000	**7,100**	2,600

Under the “Merchant Bust” scenario, 5,400–10,500 MW of AMGT can be added to California.

- Since there is no intermediate load plants currently under construction in California, no GTCC or SCGT is added.
- Under the “Merchant Bust” scenario, California can economically support 8,600 MW of AMGT.
- A significantly larger amount of AMGT can be added under the “Merchant Bust” scenario due to the lack of GTCC additions.
- A sensitivity analysis was performed to bracket the results under the “Merchant Bust” scenario.

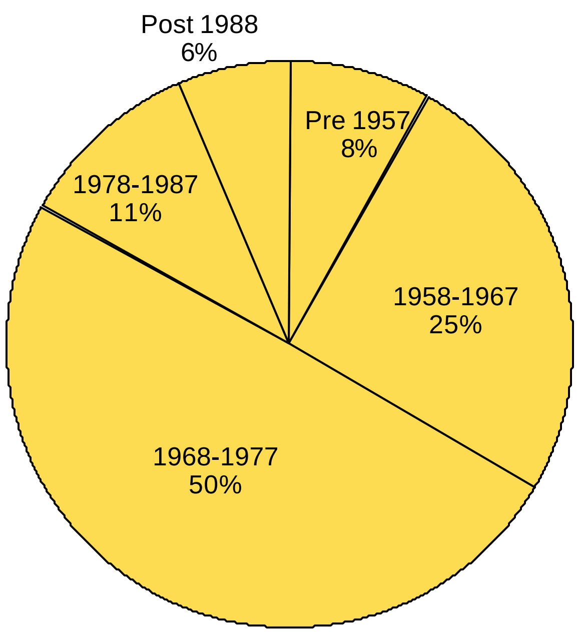
	AMGT Market Potential Sensitivities - California “Merchant Bust” Scenario		
AMGT Efficiency [LHV]	**“Merchant Bust” Base Case [MW]**	**10% Increase in Marginal Cost of Existing Facilities [MW]**	**10% Increase in Carrying Charge [MW]**
47%	7,400	9,400	**5,400**
50%	8,600	**10,500**	6,700

The displacement market in California is 1,800 to 10,500 MW.

	AMGT Additions in California		
	AMGT Market Potential Sensitivities - California “Fully Deregulated” Scenario		
AMGT Efficiency [LHV]	“Fully Deregulated” Base Case [MW]	10% Increase in Marginal Cost of Existing Facilities [MW]	10% Increase in Carrying Charge [MW]
47%	3,300	5,600	**1,800**
50%	5,000	**7,100**	2,600
	AMGT Market Potential Sensitivities - California “Merchant Bust” Scenario		
AMGT Efficiency [LHV]	“Merchant Bust” Base Case [MW]	10% Increase in Marginal Cost of Existing Facilities [MW]	10% Increase in Carrying Charge [MW]
47%	7,400	9,400	**5,400**
50%	8,600	**10,500**	6,700

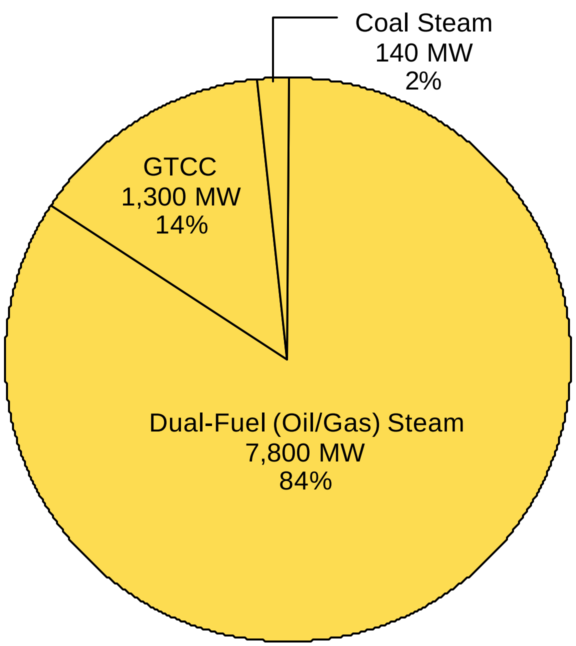
New England's intermediate capacity is dominated by relatively inefficient dual-fuel (oil and gas) steam plants.

Intermediate[1] New England Capacity by Age



Total Intermediate Capacity = 19,750 MW

Intermediate[1] New England Capacity by Technology



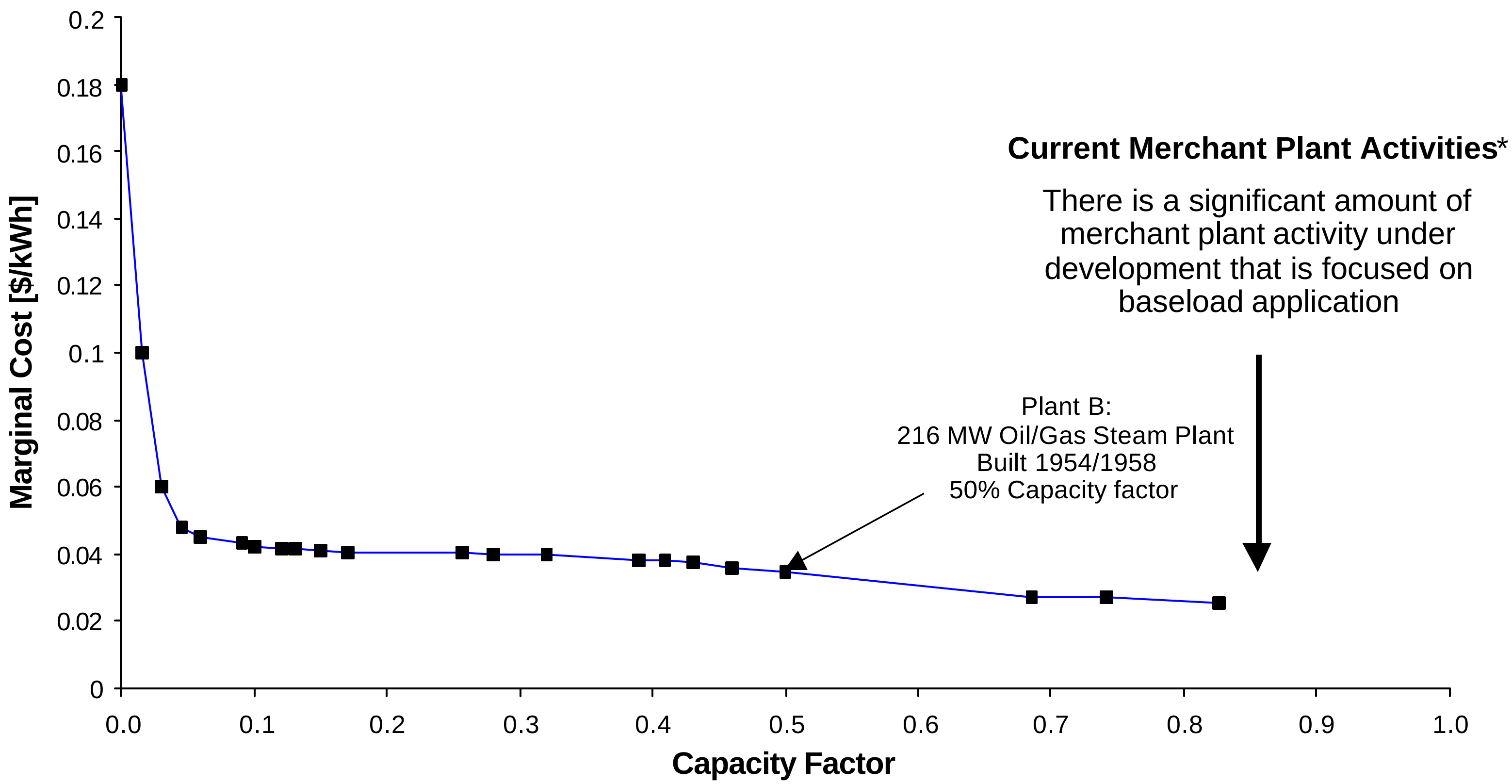
Total Intermediate Capacity = 9,300 MW

1. Intermediate is defined by >6% capacity factor and marginal cost greater than AMGT marginal cost.
   Source: RDI database

See Appendix C for details

Existing non-nuclear generation in New England was used as the starting point for assessing the market potential for AMGT in the region.

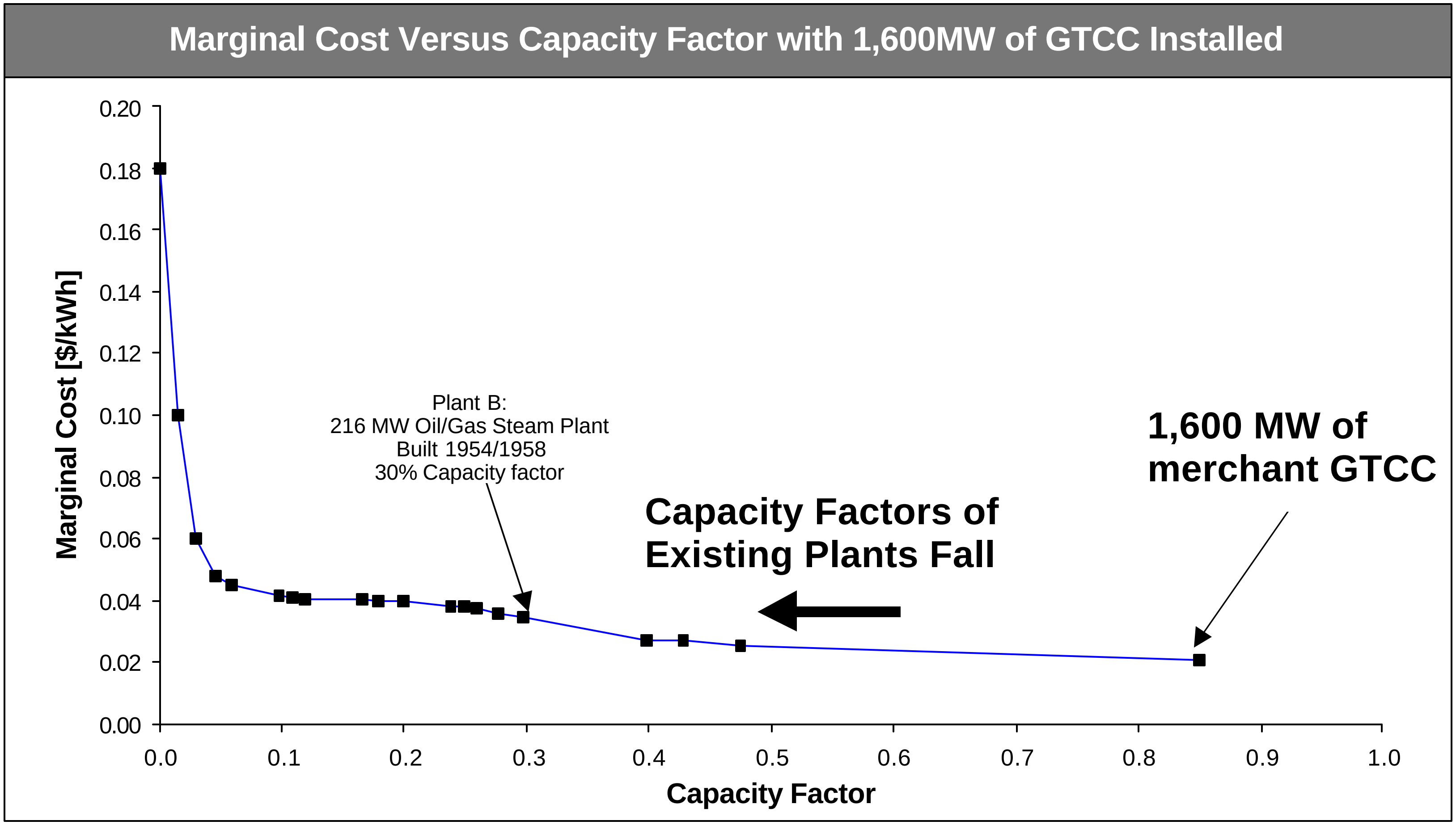
Marginal Cost Versus Capacity Factor for Existing New England Facilities



Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data.
Sources: RDI database and ADL analysis

*See Appendix C for details

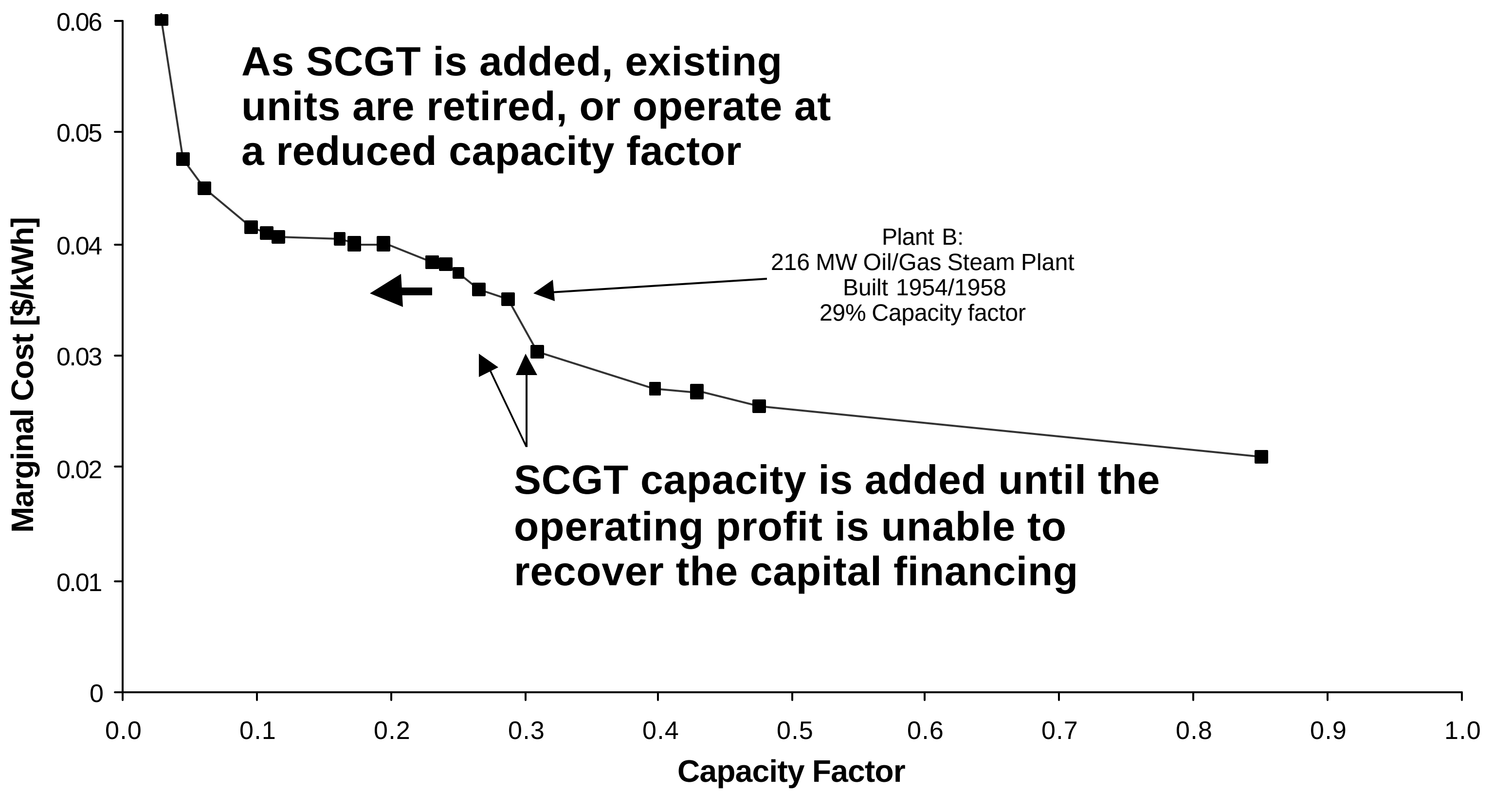
Under the Fully Deregulated scenario in New England, 1,600 MW of new GTCC capacity can be added, reducing the capacity factor of existing steam and GTCC facilities.



Note: Five left-most points represent assumed peaking capacity whose use is uninfluenced by the addition of GTCC.
GTCC assumptions: 61% eff (LHV) $500/KW total installed cost

Because AMGT is not yet available, the scenario assumes that merchant developers install simple-cycle units between now and 2005.

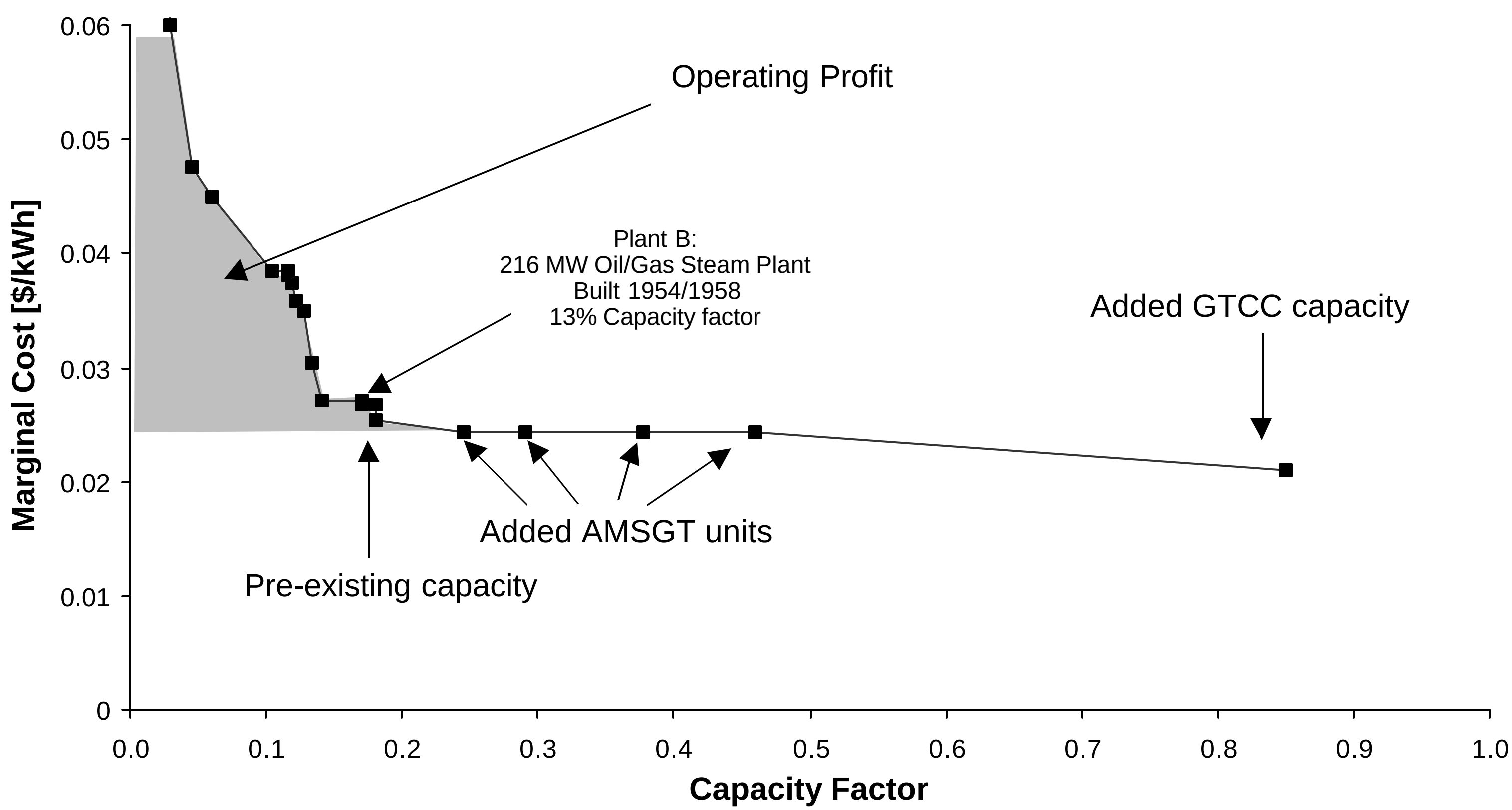
Marginal Cost Versus Capacity Factor with 100MW of SCGT Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
SCGT assumptions: 38% eff (LHV) $280/KW total installed cost

Under the "Fully Deregulated" scenario, 3,400 MW of AMGT can be installed in New England.

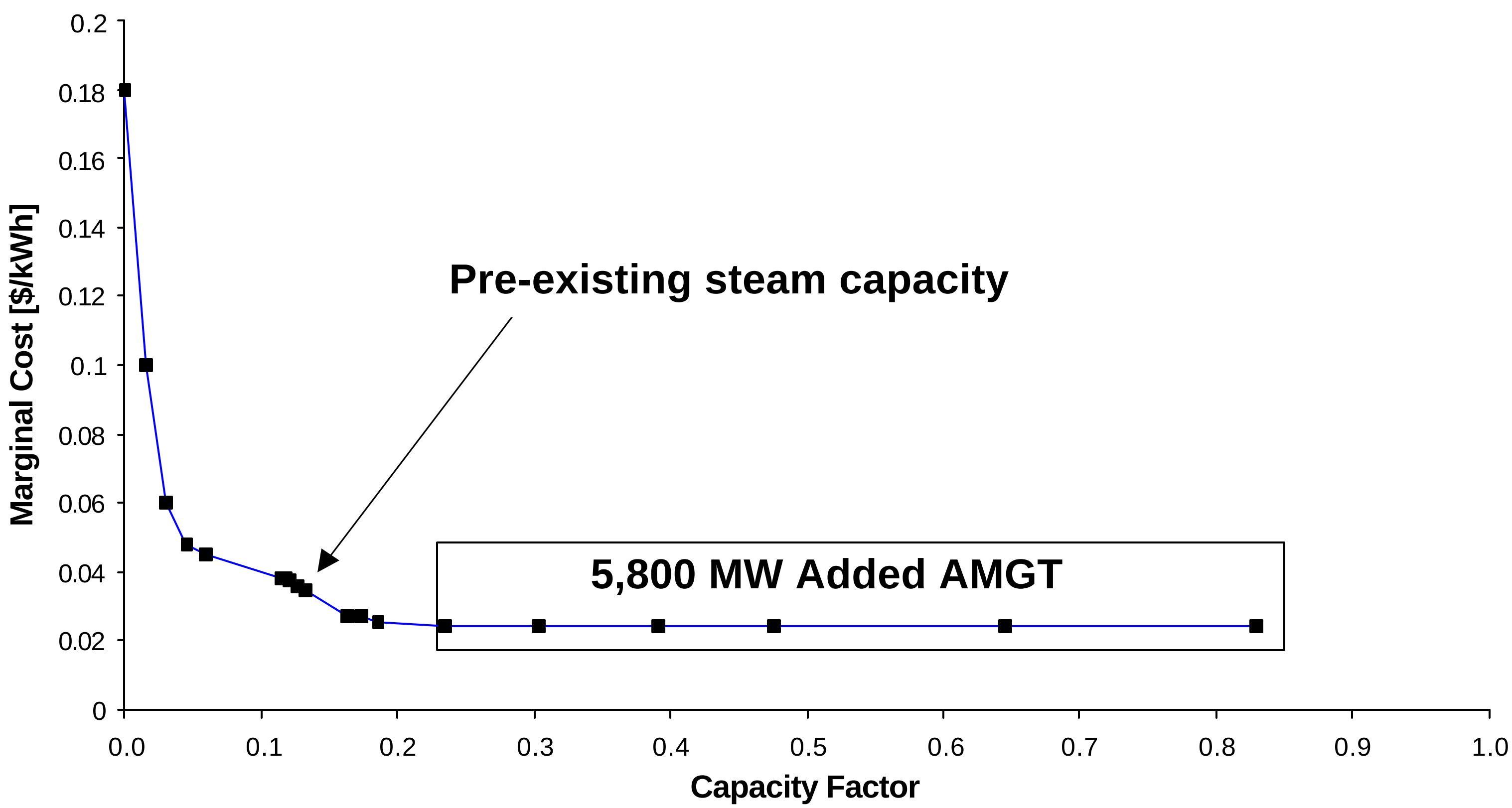
Marginal Cost Versus Capacity Factor with 3,400MW of AMGT Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
AMGT assumptions: 50% eff (LHV) $250/KW total installed cost

The "Merchant Bust" scenario for New England assumes that only GTCC currently under construction is built. This allows 5,800 MW of AMGT to be installed.

Marginal Cost Versus Capacity Factor after 5,800 MW AMGT is Added



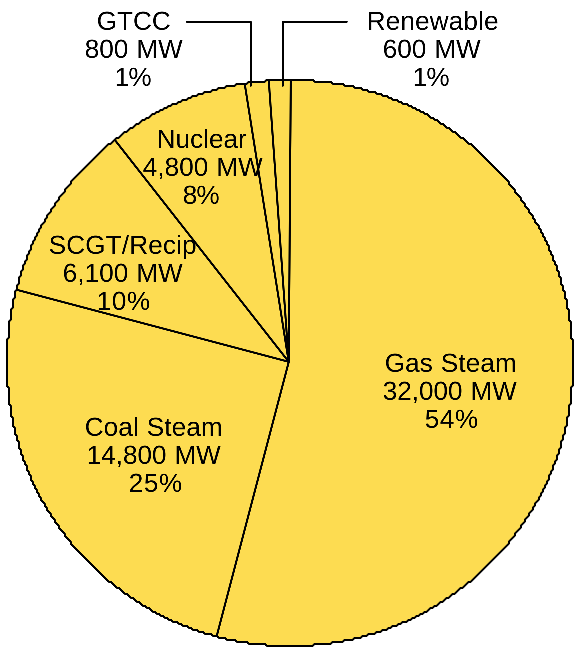
Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data.
Sources: RDI database and ADL analysis

Using the same sensitivities as the California analysis, the displacement market in New England can economically support 1,700–6,700 MW of AMGT.

	AMGT Additions in New England			
	AMGT Efficiency [LHV]	**Base Case [MW]**	**10% Increase in Marginal Cost of Existing Facilities [MW]**	**10% Increase in Carrying Charge [MW]**
Fully Deregulated	47%	2,700	4,300	**1,700**
	50%	3,400	4,700	2,700
Merchant Bust	47%	5,700	6,200	4,800
	50%	5,800	**6,700**	4,900

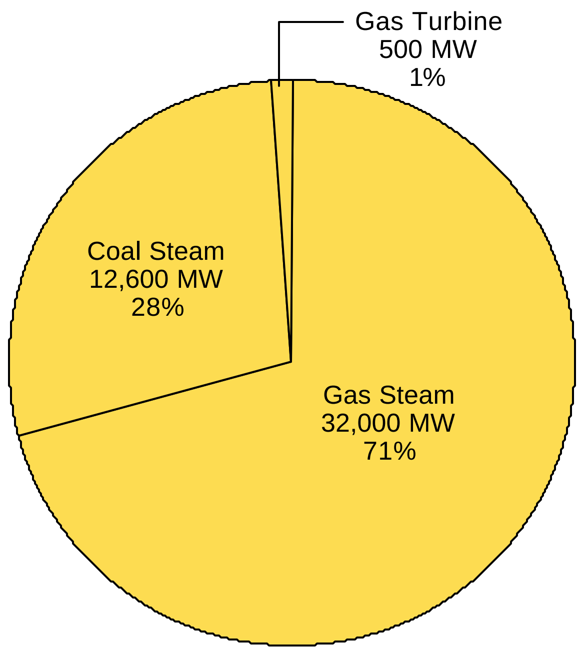
Gas and coal steam plants dominate all capacity in Texas, particularly the intermediate load capacity.

Total[1] Texas Capacity by Technology



Total Capacity = 59,100 MW

Intermediate[2] Texas Capacity by Fuel/Technology



Total Intermediate Capacity = 45,100 MW

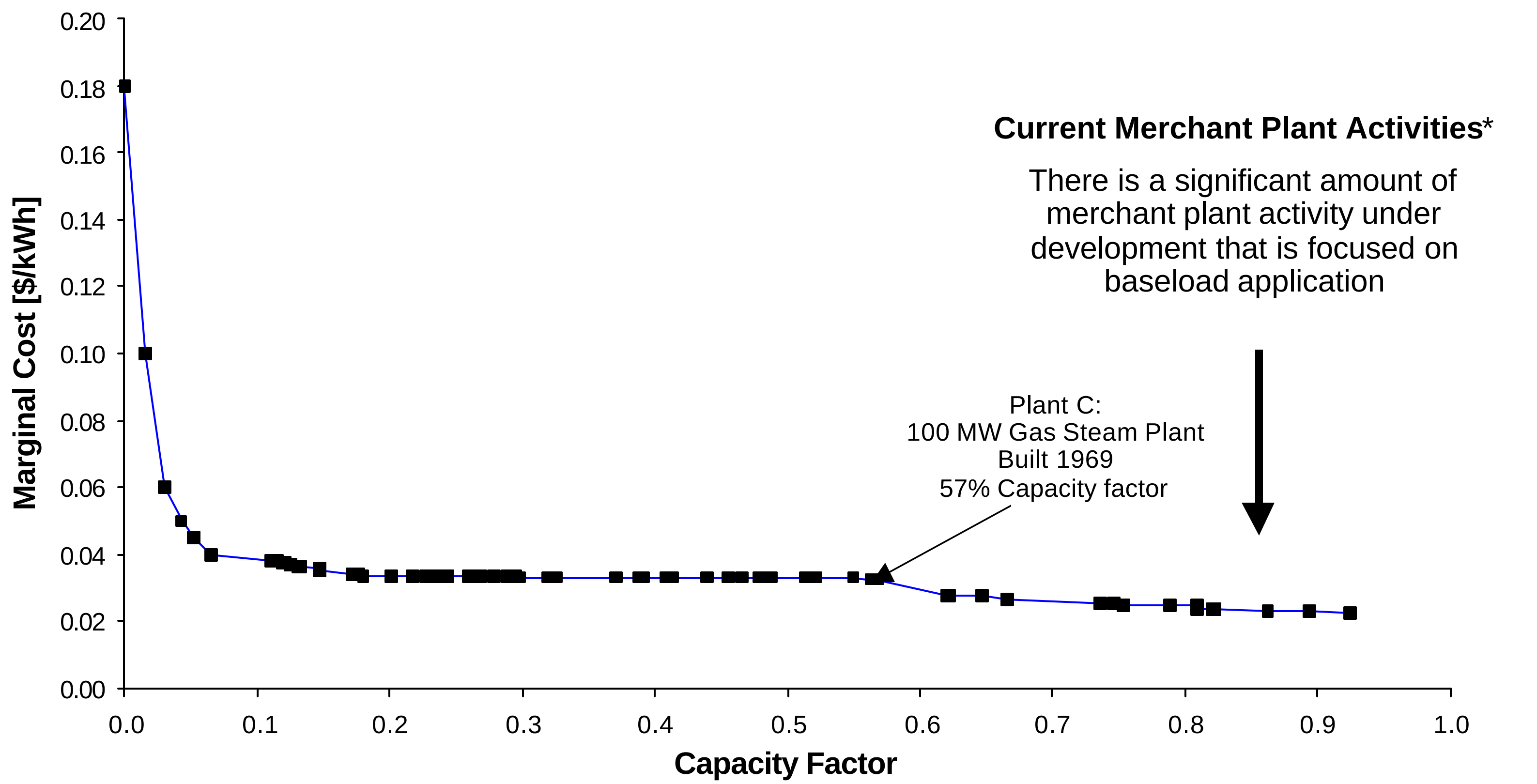
1. Source: 1999 EIA Annual Energy Outlook and RDI Database

2. Intermediate is defined by >6% capacity factor and marginal cost greater than AMGT marginal cost.
Source: RDI database

See Appendix C for details

Texas has a relatively flat marginal cost curve.

Marginal Cost Versus Capacity Factor for Existing Texas Facilities

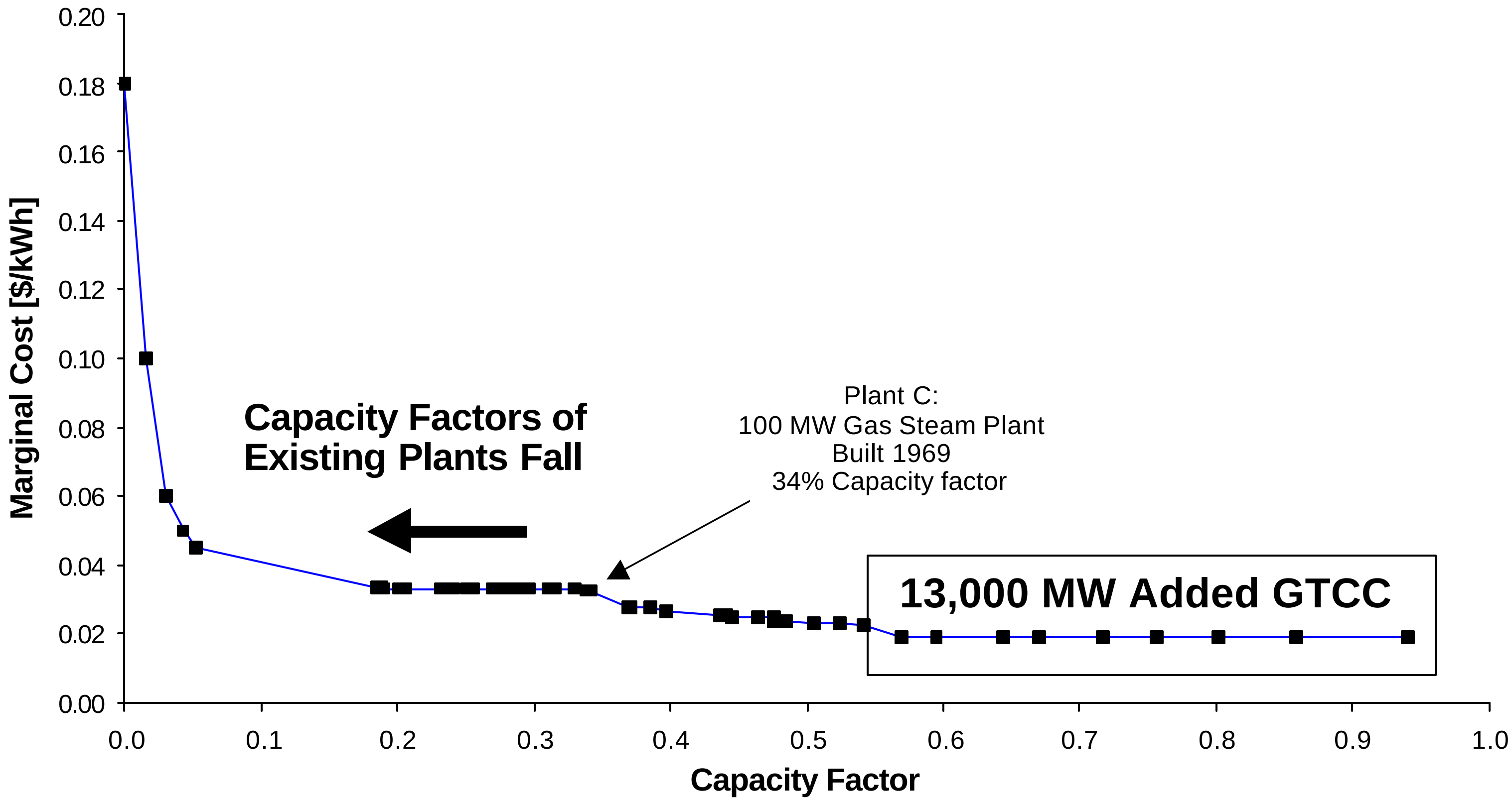


Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data.
Sources: RDI database and ADL analysis

*See Appendix C for details

In the "Fully Deregulated" scenario, 13,000 MW of GTCC can be added in ERCOT.

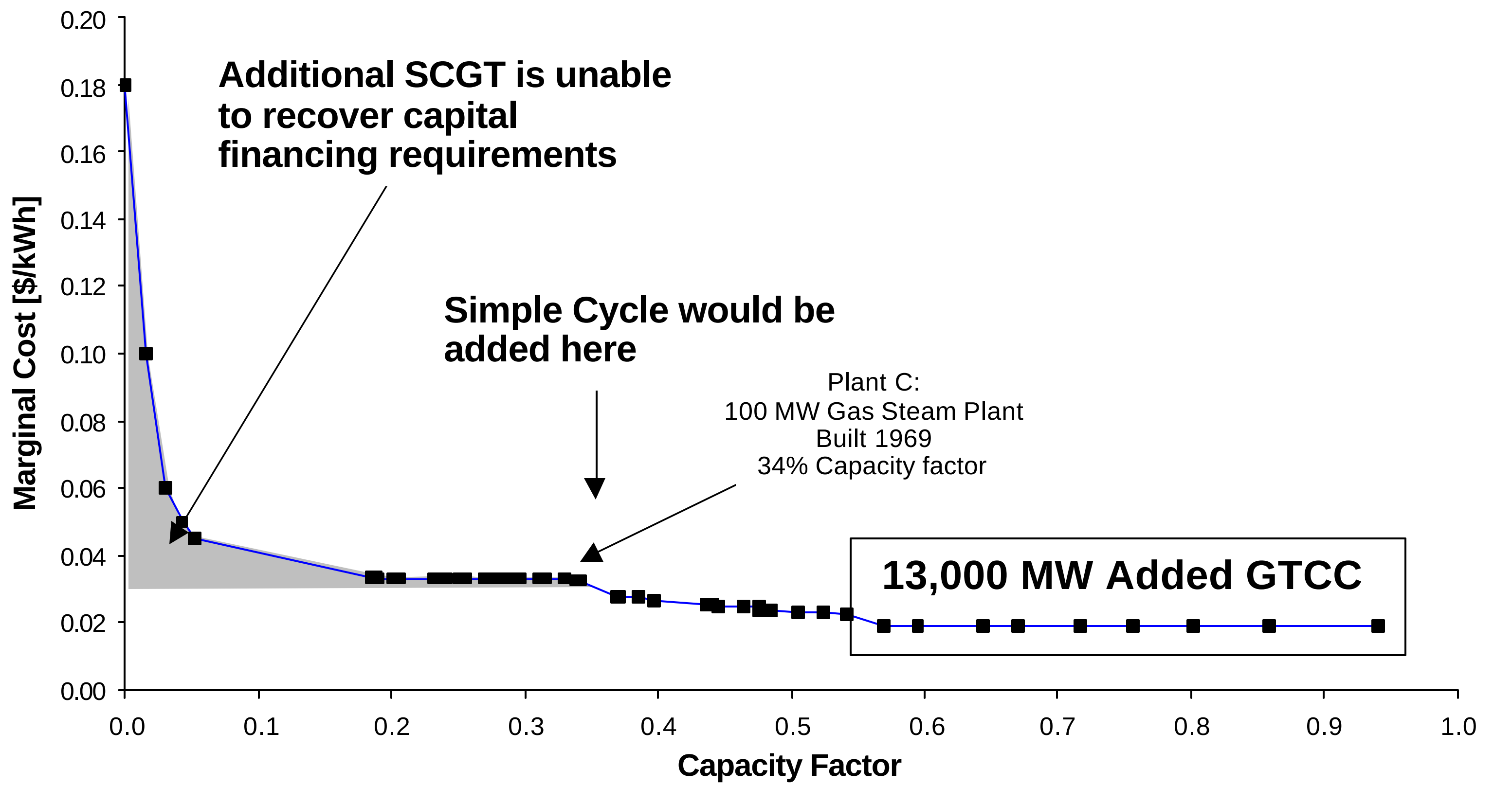
Marginal Cost Versus Capacity Factor with 13,000 MW of GTCC Installed



Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data.
Sources: RDI database and ADL analysis

New simple-cycle units cannot be added in Texas under the "Fully Deregulated" scenario because they are unable to recover capital financing requirements.

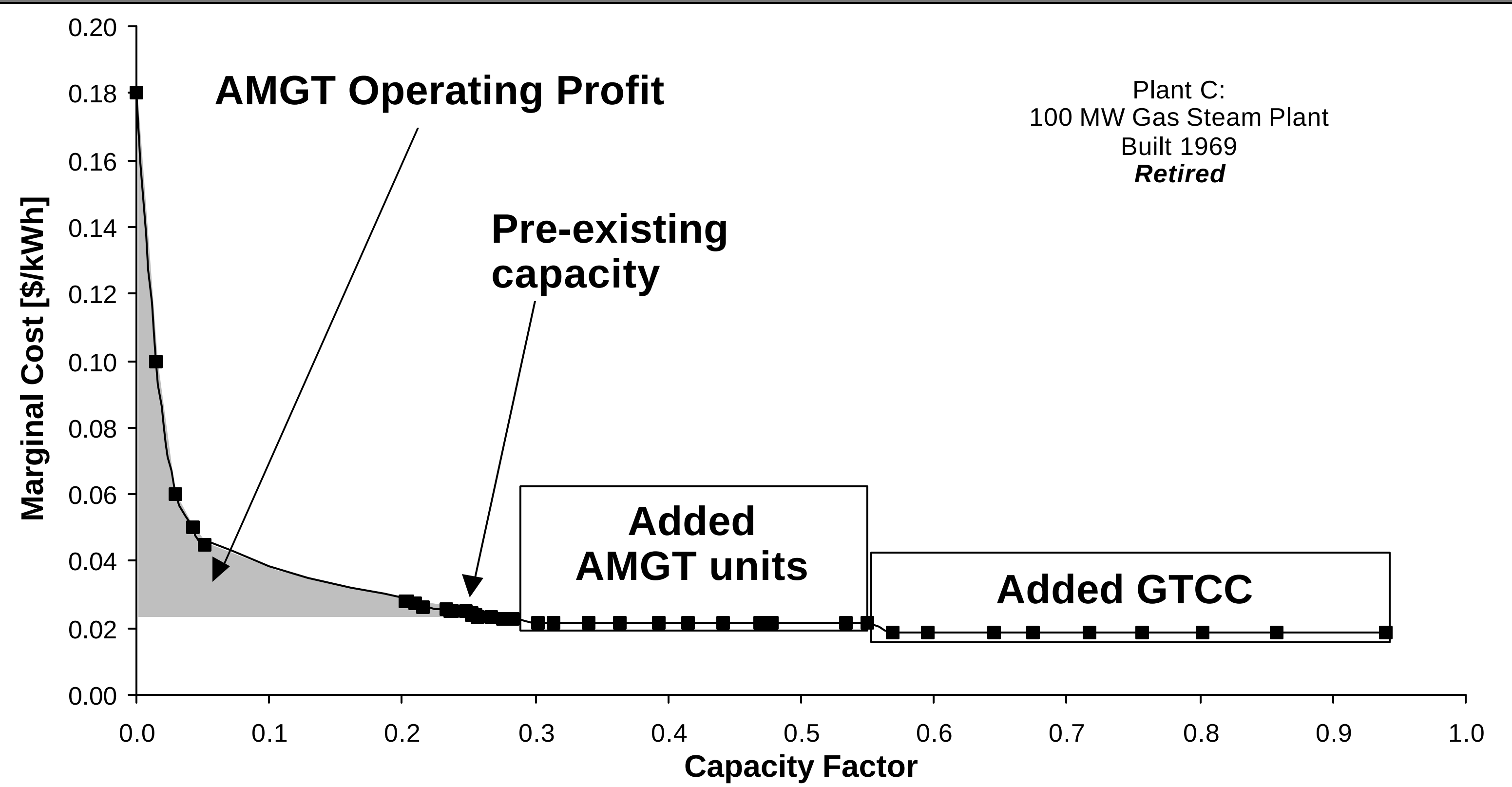
Marginal Cost Versus Capacity Factor with 13,000 MW of GTCC Installed



Note: The five left-most points do not represent actual generating units, rather, they are estimates of the peaking market based on preliminary 1998 California PX data.
Sources: RDI database and ADL analysis

Under the "Fully Deregulated" scenario over 17,000 MW of AMGT capacity can be added until the operating profit is unable to recover the capital financing requirements.

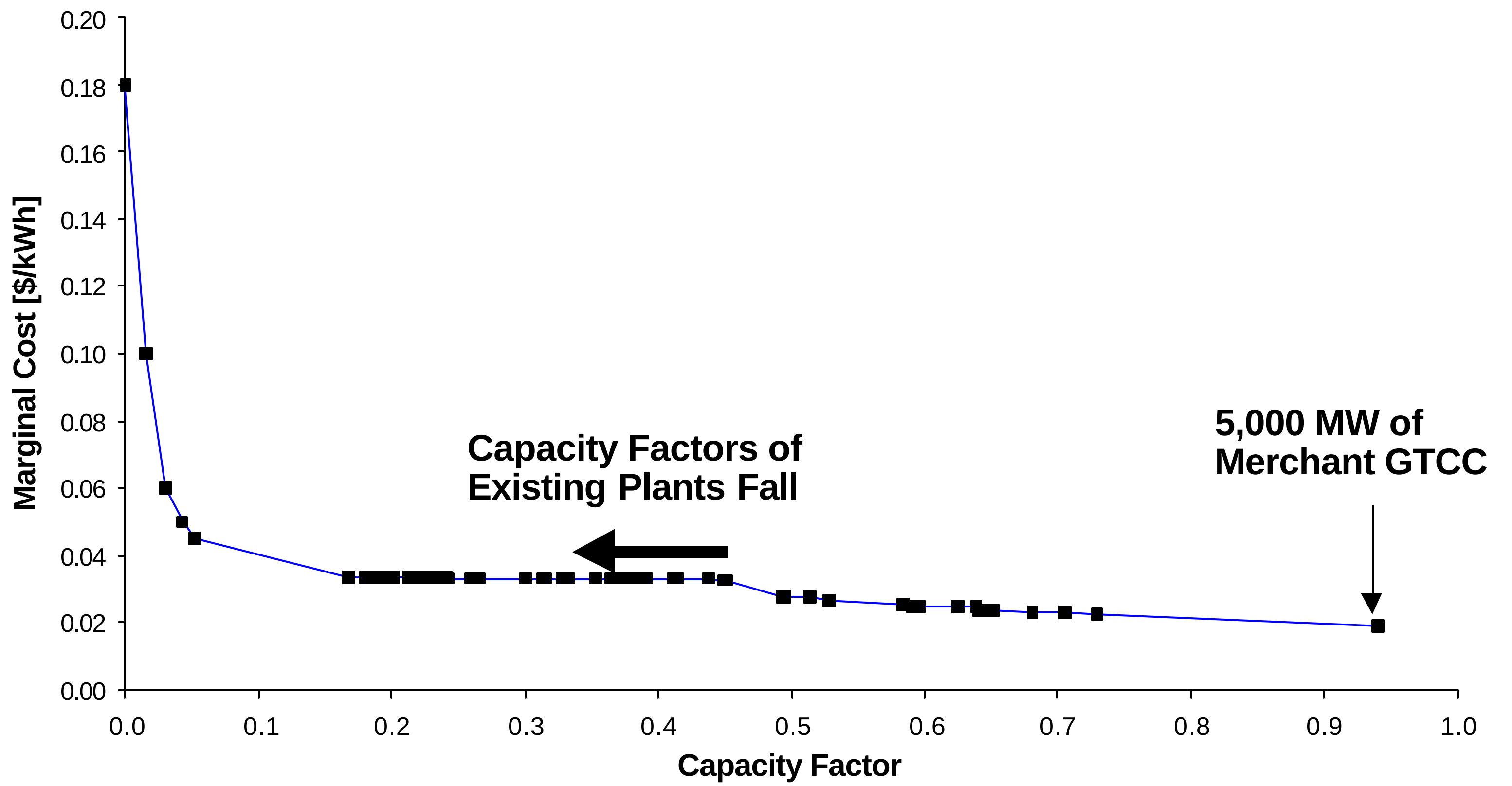
Marginal Cost Versus Capacity Factor with 21,000 MW of AMGT Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
AMGT assumptions: 47% eff (LHV) $250/KW total installed cost

In the "Merchant Bust" scenario, only 5,000 MW of new GTCC capacity is added to represent planned merchant activity, reducing the capacity factor of existing steam and GTCC facilities.

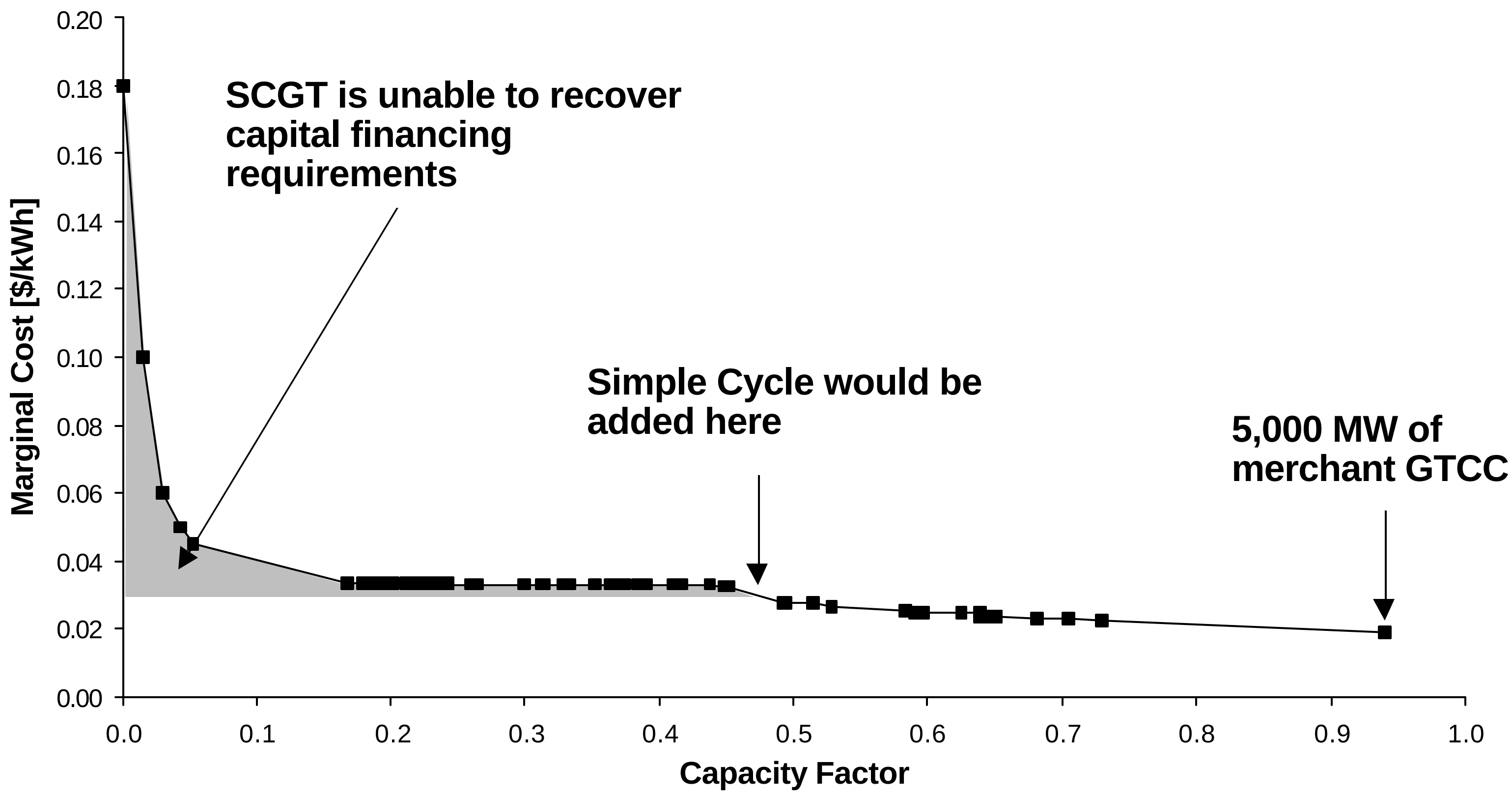
Marginal Cost Versus Capacity Factor with 5,000 MW of GTCC Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
GTCC assumptions: 61% eff (LHV) $500/KW total installed cost

New simple-cycle units cannot be added because they are unable to recover capital financing requirements.

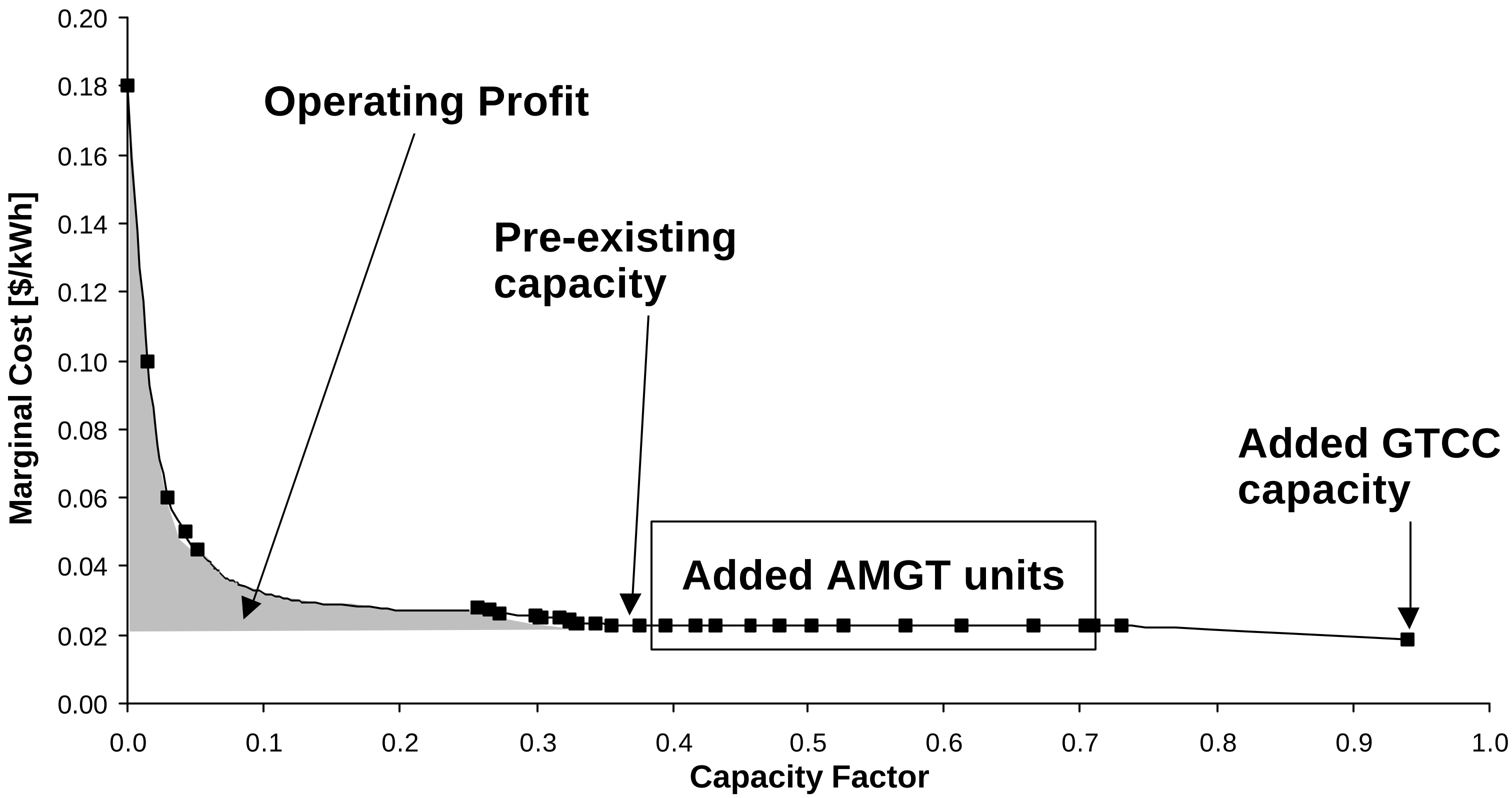
Marginal Cost Versus Capacity Factor with 5,000 MW of GTCC Installed



Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
SCGT assumptions: 38% eff (LHV) $280/KW total installed cost

Over 21,000 MW of AMGT capacity can be added until the operating profit is unable to recover the capital financing requirements.

Marginal Cost Versus Capacity Factor with 21,000 MW of AMGT Installed

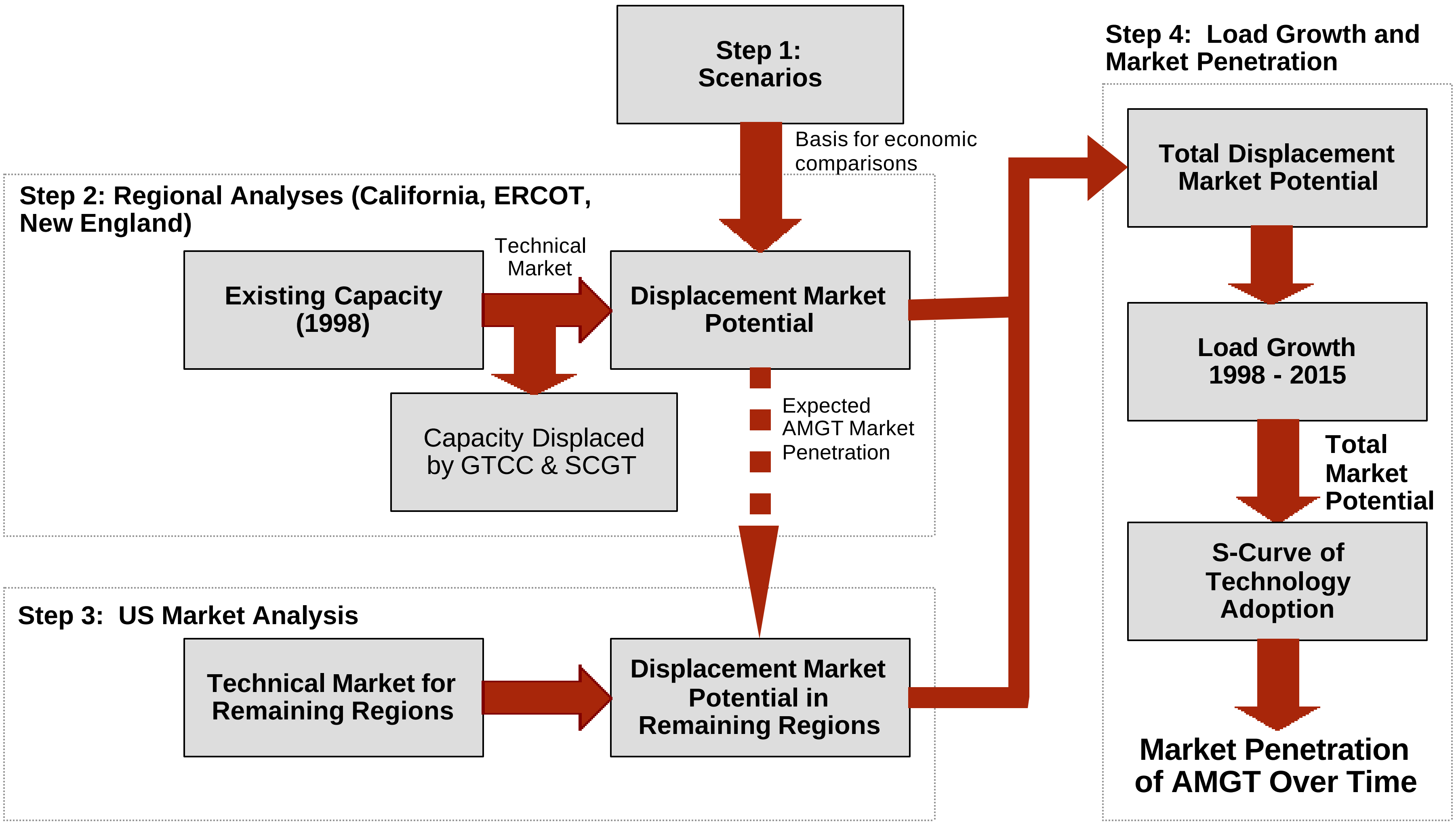


Note: Five left-most points represent assumed peaking capacity that is uninfluenced by the addition of GTCC.
AMGT assumptions: 47% eff (LHV) $250/KW total installed cost

Using the same sensitivities as in New England and California, between 11,000 and 32,000 MW of AMGT can be added to Texas.

	AMGT Additions in Texas			
	AMGT Efficiency [LHV]	**Base Case [MW]**	**10% Increase in Marginal Cost of Existing Facilities [MW]**	**10% Increase in Carrying Charge [MW]**
Fully Deregulated	47%	13,000	22,000	**11,000**
	50%	17,000	24,000	16,000
Merchant Bust	47%	21,000	31,000	17,000
	50%	25,000	**32,000**	20,000

In the third step of the analysis, the displacement market potential in the remaining regions is found by scaling up from the technical market in those regions based on the expected AMGT market penetration from Step 2.



The three regions analyzed in Step 2 represent three levels of penetration for AMGT.

Regional Analysis	Intermediate Load Displacement Technical Market Potential* (MW)	Intermediate Load Economic Market Potential (MW)	Penetration of AMGT
ERCOT	26,000	11,000–32,000	42%–125%**
New England	7,900	1,700–6,700	20%–85%
California	18,000	1,800–10,500	10%–58%

*Collaborative Advanced Gas Turbine Report, “Flexible Mid-Sized Gas Turbine—Preliminary Market Analysis,” October 30, 1997.

**High penetration rate is caused by AMGT displacing baseload capacity.

The penetration for AMGT in the remaining regions was characterized based on fuel mix for intermediate load in that region.

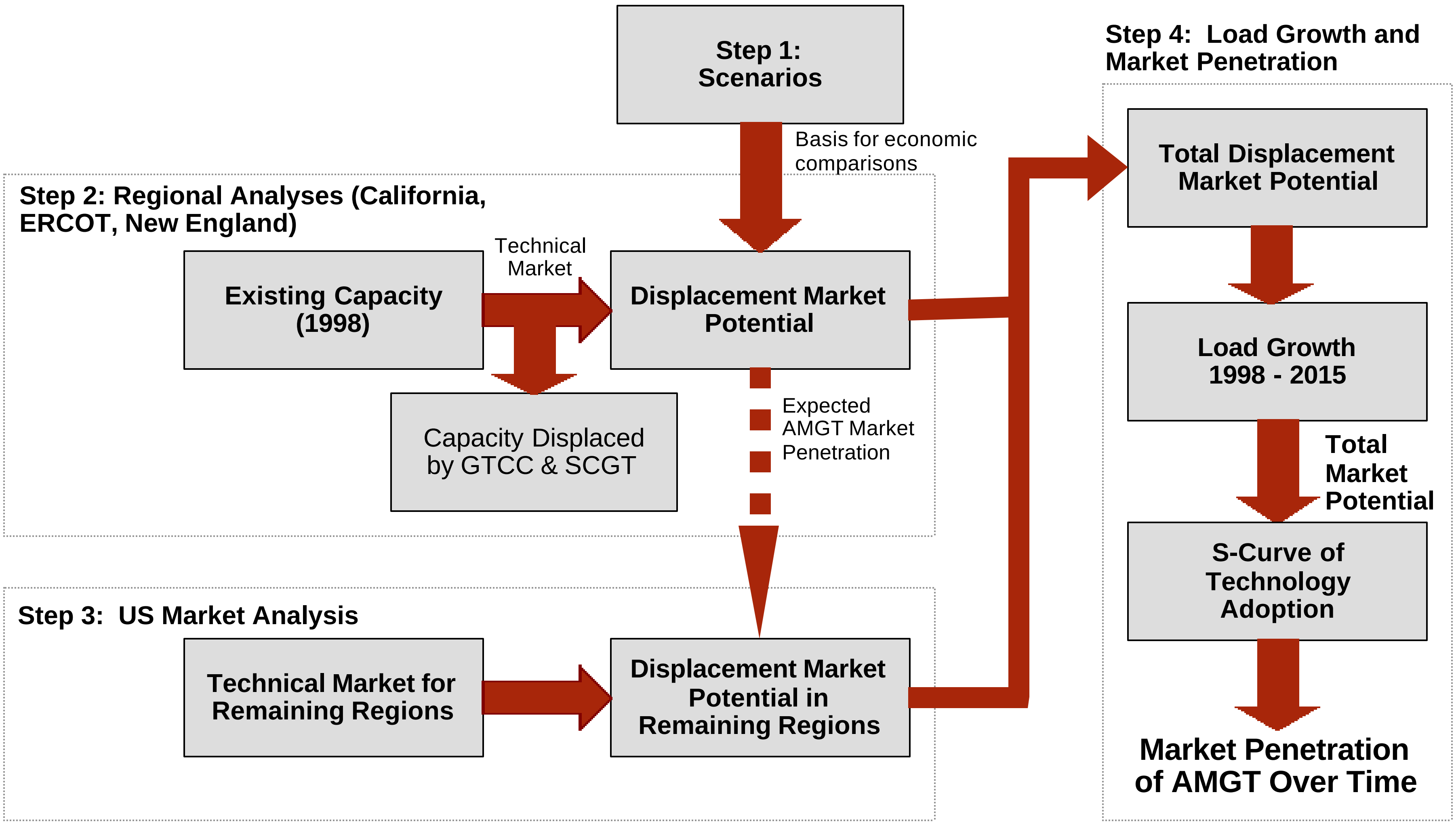
Region Type by Fuel	Region	Intermediate Load Fuel Mix*	Technical Displacement Market Potential (MW)*	Regional Analysis Basis for Penetration
Gas	SPP	Coal—2% Gas—98%	27,800	ERCOT
Gas & Oil	New York	Coal—11% Gas—51% Oil—38 %	12,000	New England
	FRCC	Coal—10% Gas—20% Oil—70%	12,700	
Coal	WSCC (less CA)	Coal—78% Gas—22%	5,800	California
	MAPP	Coal—89% Gas—11%	2,000	
	MAIN	Coal—78% Gas—22%	12,000	
	SERC	Coal—95% Gas—5%	1,300	
	MAAC	Coal—72% Oil—18%	8,600	
	ECAR	Coal—100%	6,900	

*Collaborative Advanced Gas Turbine Report," Flexible Mid-sized Gas Turbine–Preliminary Market Analysis," October 30, 1997.

The AMGT displacement market potential for the regions outside of the three analyzed in detail was projected based on the expected penetration of AMGT and the technical market potential in these regions.

	Projected AMGT Regional Displacement Market Potential (MW)			
	Basis for Projection			Overall Results
	Texas Regional Analysis	New England Regional Analysis	California Regional Analysis	
California			1,800–10,500	1,800–10,500
New England		1,700–6,700		1,700–6,700
Texas	11,000–32,000			11,000–32,000
WSCC (less CA)			580–3,400	580–3,400
MAPP			200–1,200	200–1,200
SPP	11,800– 34,200			11,800–34,200
MAIN			1,200–7,000	1,200–7,000
ECAR			700–4,000	700–4,000
SERC			100– 760	100–760
FRCC		2,700–10,800		2,700–10,800
MAAC			900– 5,000	900–5,000
New York		2,600–10,200		2,600–10,200

The fourth step of the analysis accounts for load growth and market penetration of a new technology over time.

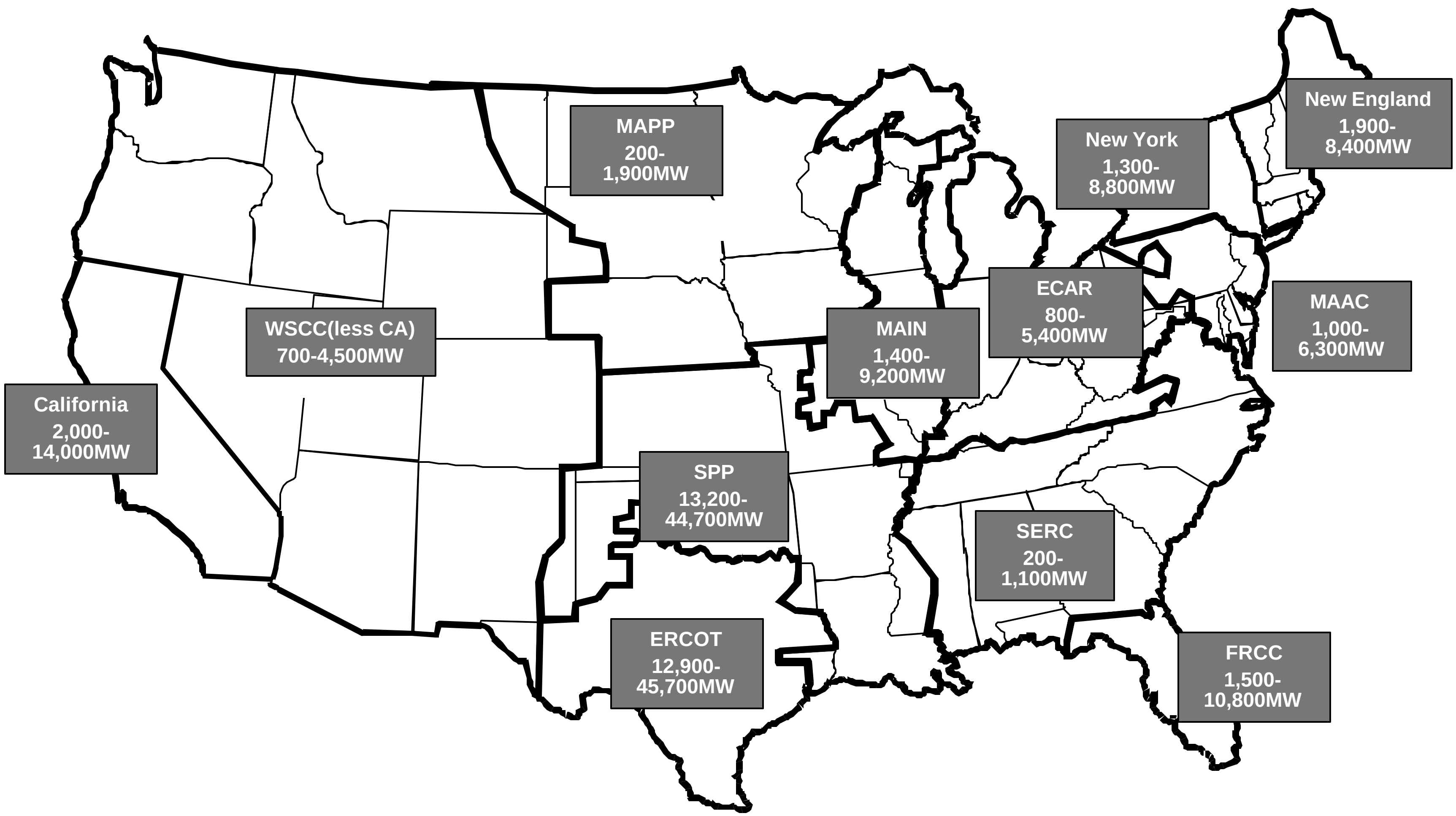


Load growth is added to displacement market to arrive at the overall AMGT market potential in the 2005-2015 time frame.

	2005-2015 Displacement Market Potential (MW)		Annual Capacity Growth[1] (%)	2005-2015 Displacement and Load Growth Market Potential (MW)	
	Pessimistic	Optimistic		Pessimistic	Optimistic
California	1,800	10,500	1.6	2,000	14,000
New England	1,700	6,700	1.3	1,900	8,400
Texas	11,000	32,000	2.0	12,900	45,700
WSCC (less CA)	580	3,400	1.6	700	4,500
MAPP	200	1,200	1.7	200	1,900
SPP	11,800	34,200	1.5	13,200	44,700
MAIN	1,200	7,000	1.5	1,400	9,200
ECAR	700	4,000	1.6	800	5,400
SERC	100	760	2.3	200	1,100
FRCC	1,300	7,400	2.1	1,500	10,800
MAAC	900	5,000	1.3	1,000	6,300
New York	1,200	7,000	1.3	1,300	8,800

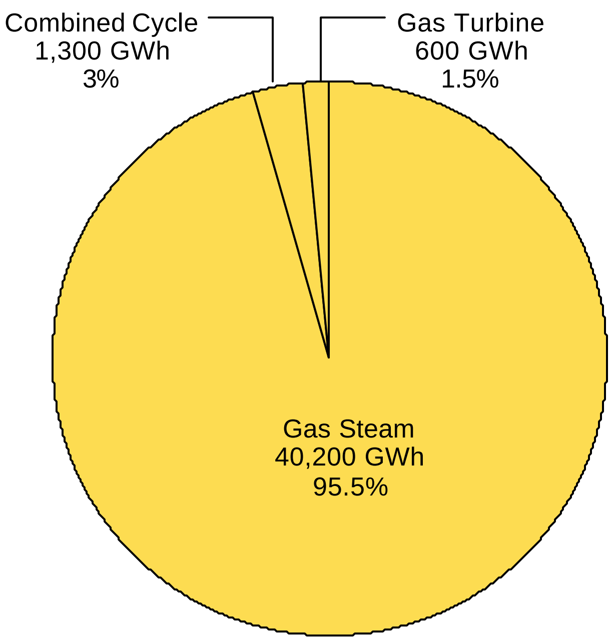
[1] Annual capacity growth projections from NERC “Reliability Assessment 1997-2007”

The overall load growth and displacement market potential for AMGT is between 37,000 and 160,000 MW in the 2005–2015 timeframe.



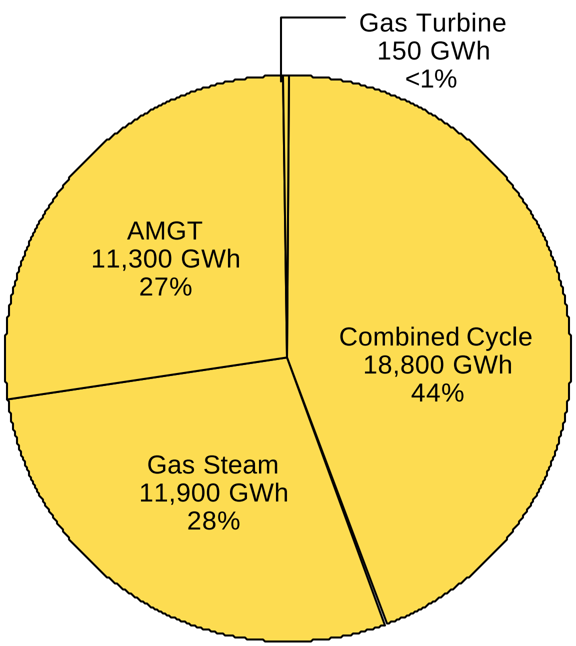
Over two-thirds of the intermediate generation from gas steam plants in California will be displaced by new GTCC and AMGT units.

Intermediate Generation Mix Before GTCC and AMGT Additions



Total Intermediate Generation = 42,100 GWh

Intermediate Generation Mix After GTCC and AMGT Additions*

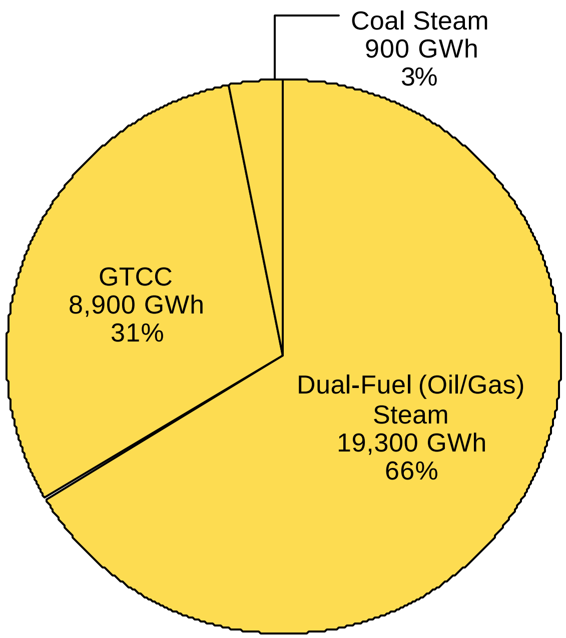


Total Intermediate Generation = 42,100 GWh

*8,000 MW (average of market potential range) from 2005–2015

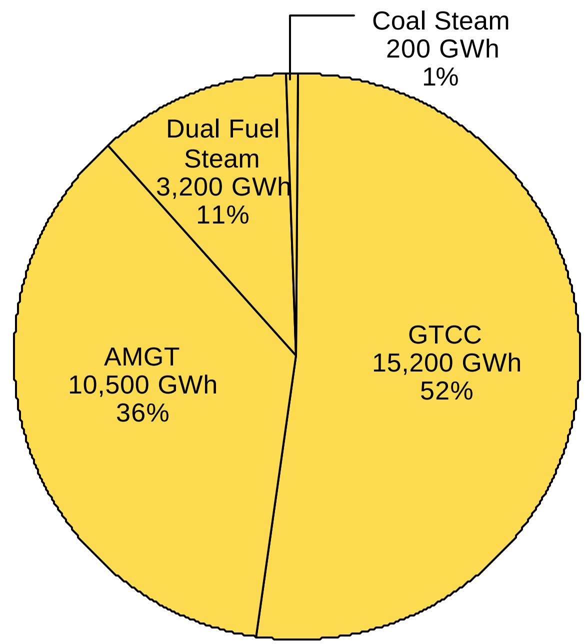
Most of New England's dual-fuel steam generation will be displaced by new GTCC and AMGT generation.

Intermediate Generation Mix Before GTCC and AMGT Additions



Total Intermediate Generation = 29,100 GWh

Intermediate Generation Mix After GTCC and AMGT Additions*

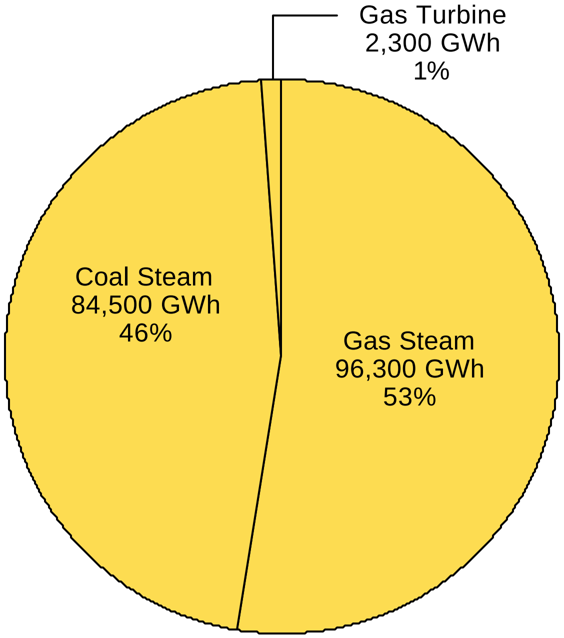


Total Intermediate Generation = 29,100 GWh

*5,150 MW (average of market potential range) from 2005–2015.

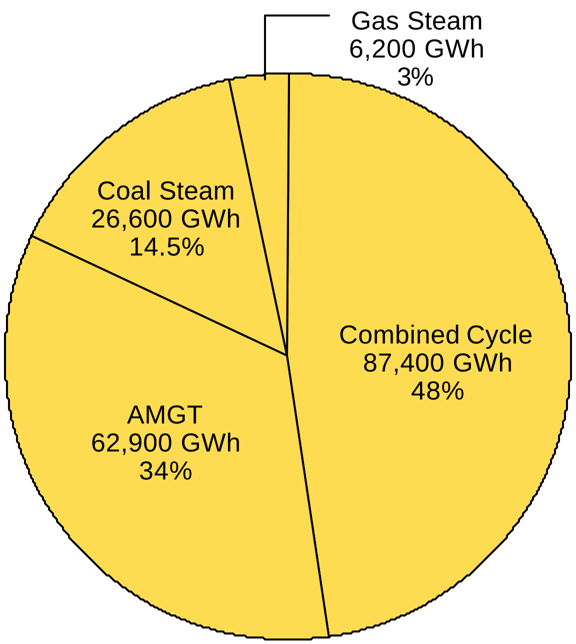
Most of the gas steam and over two-thirds of the coal steam generation are replaced by GTCC and AMGT generation.

Intermediate Generation Mix Before GTCC and AMGT Additions



Total Intermediate Generation =183,100 GWh

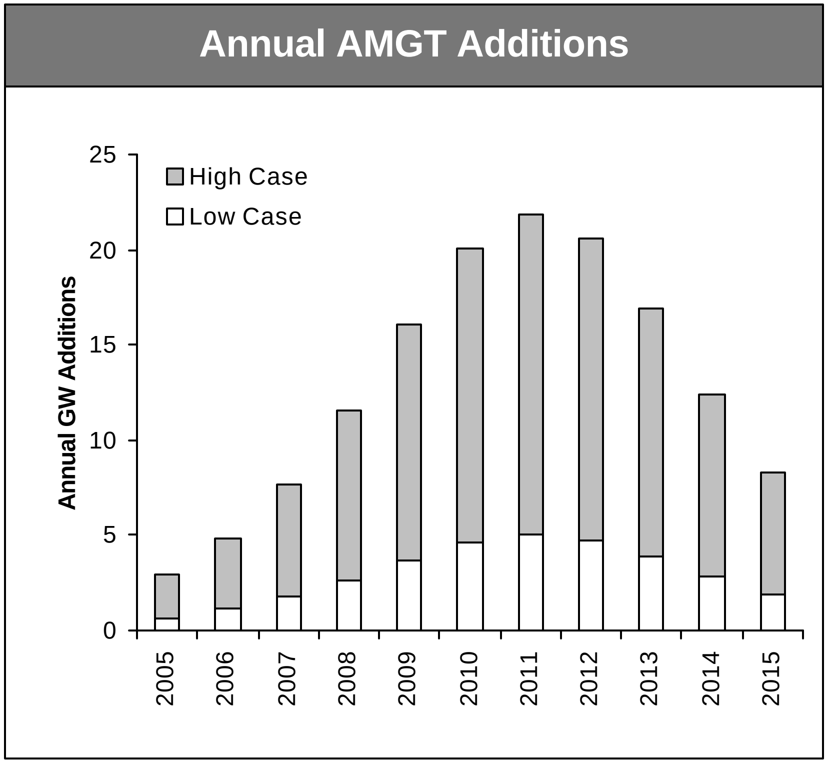
Intermediate Generation Mix After GTCC and AMGT Additions*

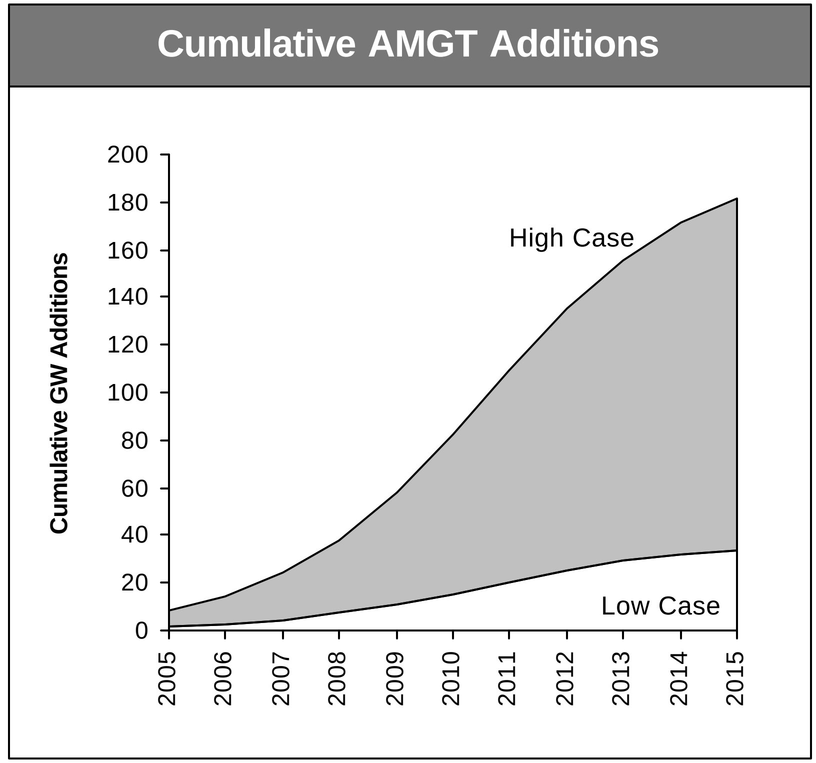


Total Intermediate Generation = 183,100 GWh

*29,300 MW (average of market potential range) from 2005–2015.

However, there will be a delay in getting the new technology accepted by the market place. AMGT adoption is projected to follow the typical "S" curve of technology substitution.

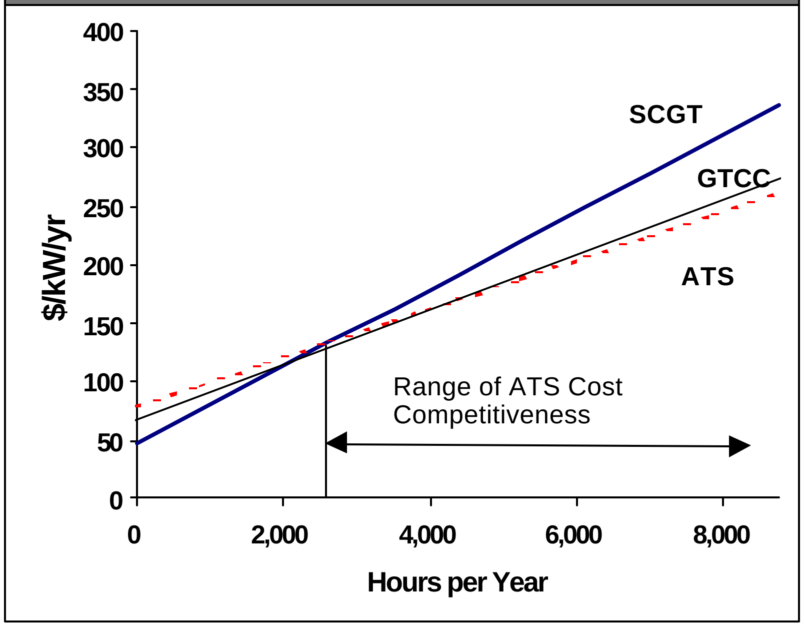




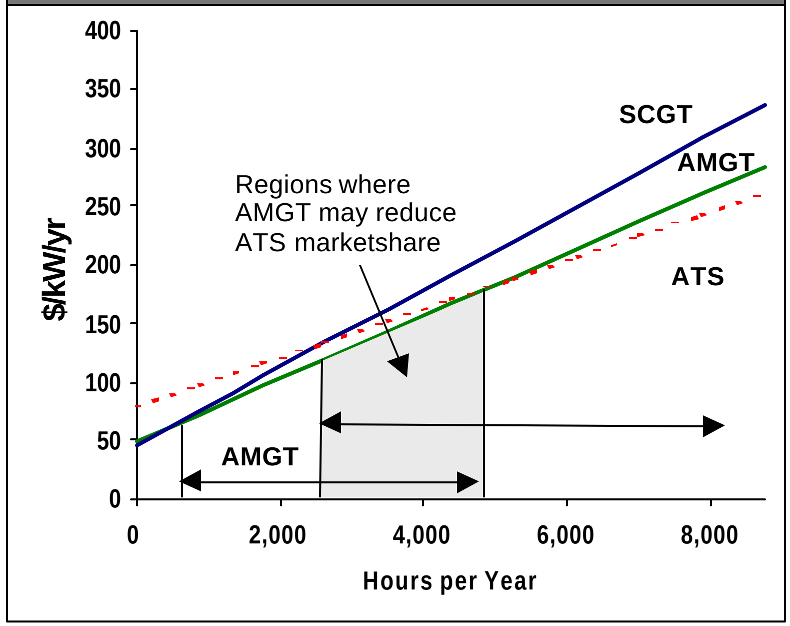
The annual AMGT addition is projected to peak approximately 8 years after commercial product introduction.

At first glance there would appear to be an overlap between where the large ATS gas turbines will operate and the AMGT.

ATS vs. Current GTCC



ATS vs. AMGT



- When the ATS gas turbine is introduced it will be more economical than existing SCGT's and GTCC's when operated > ~2,500 hours.
- The AMGT when it is introduced would be the most economical option when it is operated from ~500 hours to ~2,500 hours per year.
- There would appear to be overlap between ATS and AMGT when both were operating at ~2,500 to ~4,800 hours per year.

It is unlikely, however, that AMGT will compete directly with ATS in the marketplace.

- The ATS engines will be introduced 6–8 years before an AMGT is commercially available.
- The ATS is specifically designed for baseload capacity:
  - Cycle is designed to achieve max energy efficiency.
  - ATS turbines would be 3–10 times larger than the AMGT.
  - ATS turbines would have longer start-up times than the AMGT.
  - The amount of cycling duty at 30–40% capacity factor (2,500–3,500 hours) may increase ATS's marginal operating costs in this range.
- Efficiency will be traded off for maximum cycling capability in the AMGT technology.

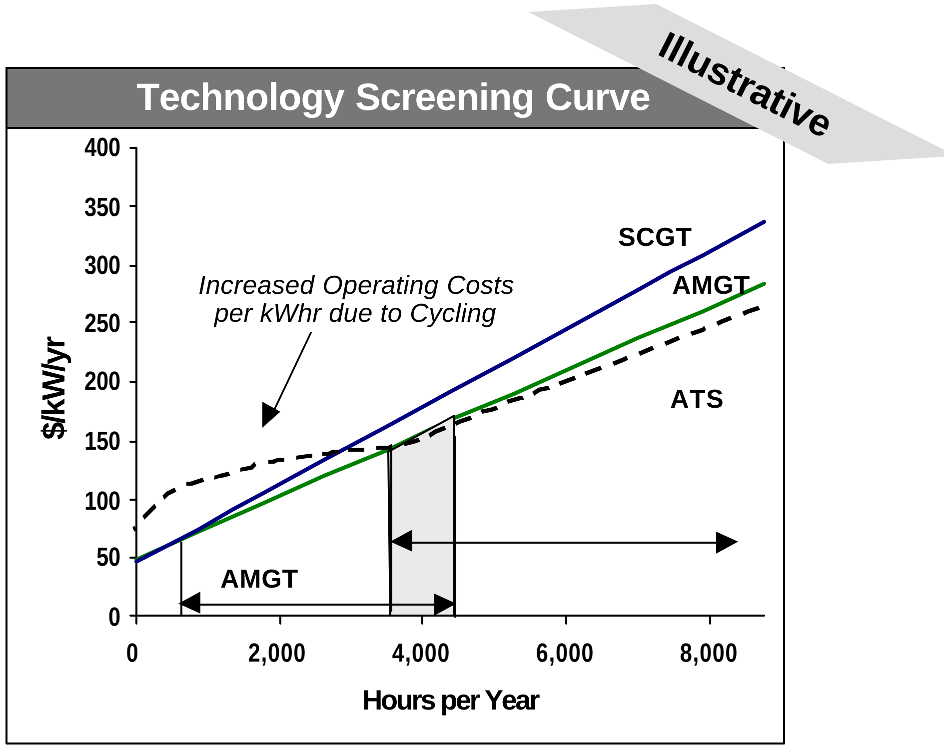
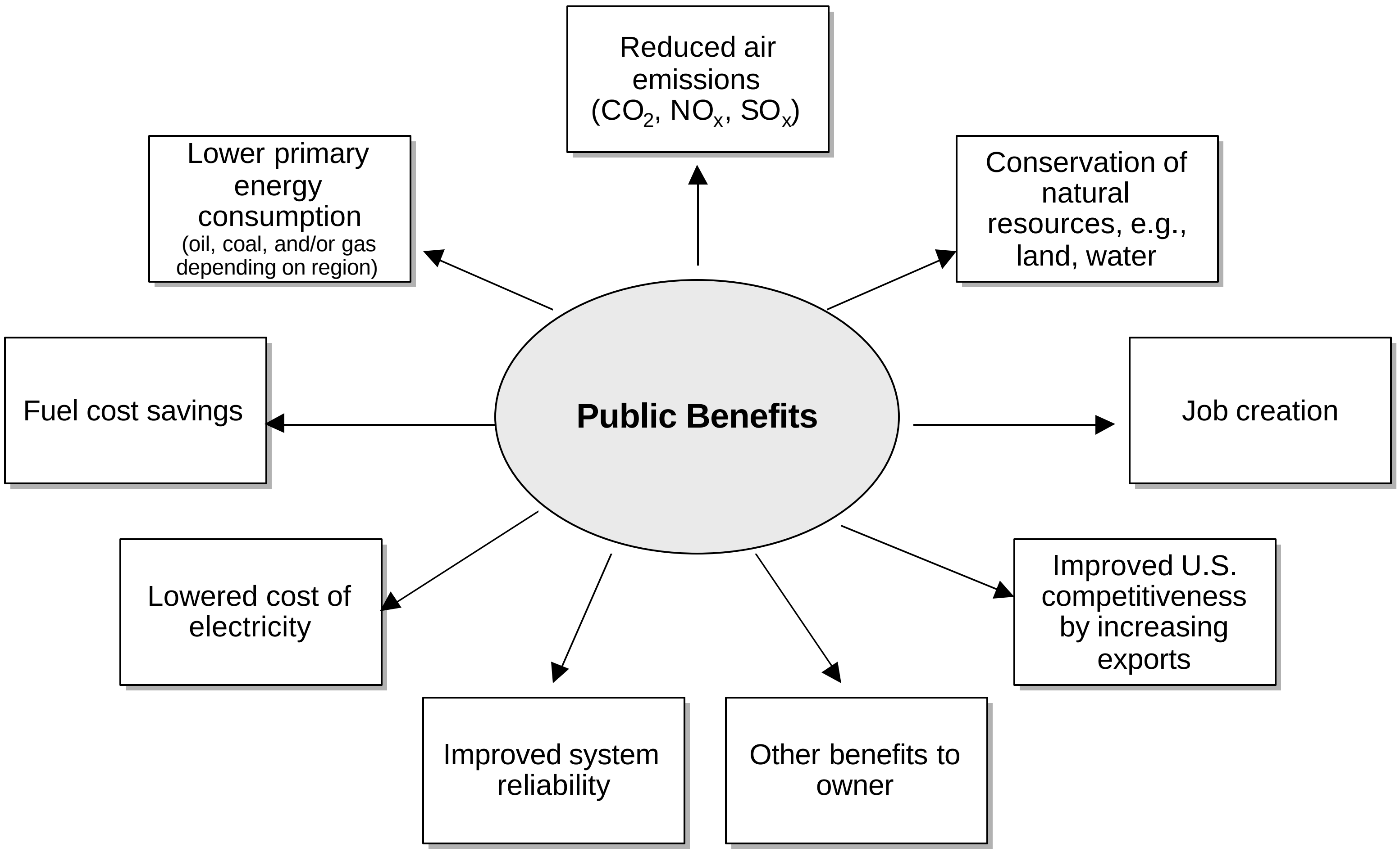
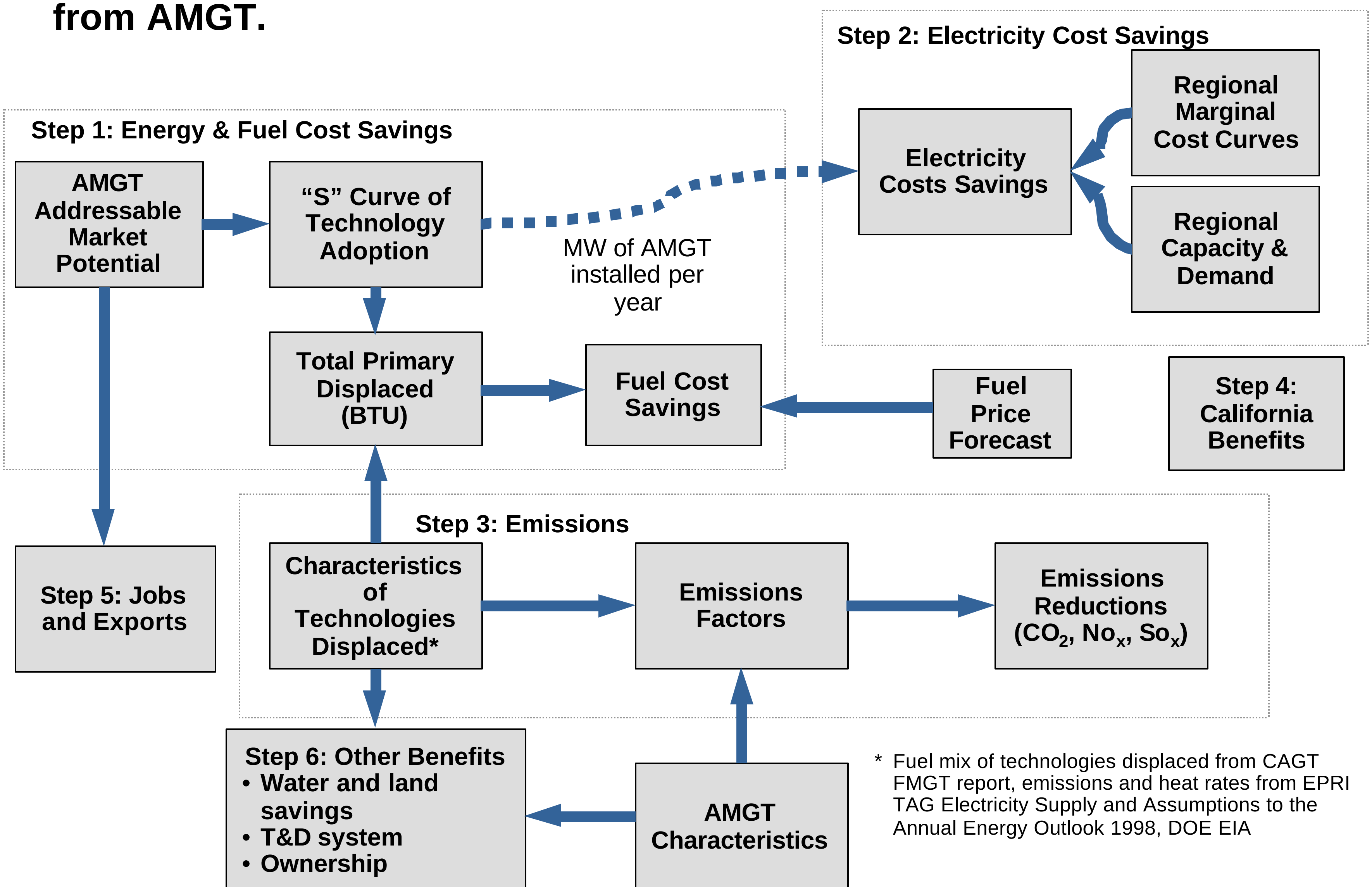


Table of Contents

The adoption of advanced mid-sized gas turbines will lead to public benefits.

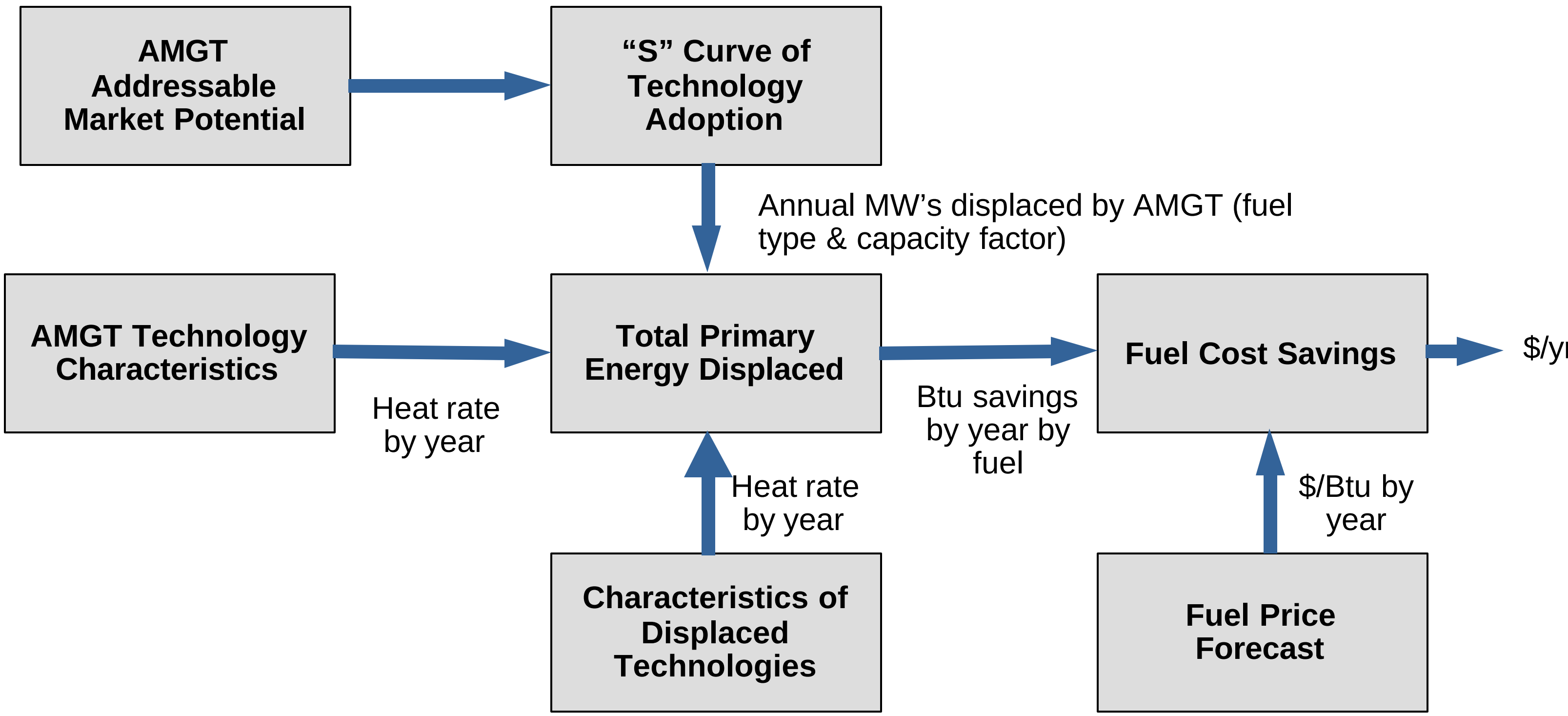


A six-step approach was used to calculate public benefits resulting from AMGT.



* Fuel mix of technologies displaced from CAGT FMGT report, emissions and heat rates from EPRI TAG Electricity Supply and Assumptions to the Annual Energy Outlook 1998, DOE EIA

The first step in the public benefits analysis requires three calculations to calculate energy and fuel cost savings.



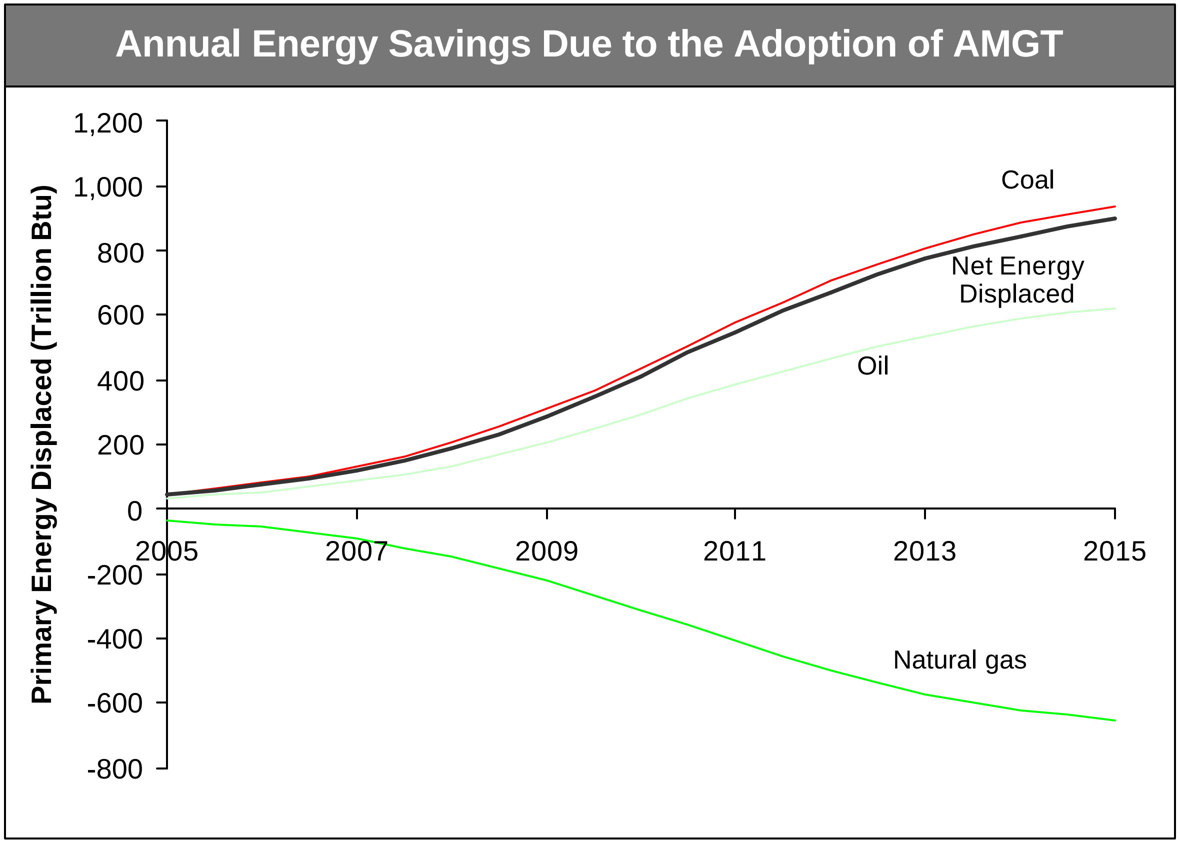
Step 1.1: Calculate Δ Heat Rate (AMGT Heat Rate - Displaced Technology Heat Rate)

Note: it is assumed heat rates will improve over time for all technologies (see Appendix D for details)

Step 1.2: Total Primary Energy displaced per year (by fuel type) = Δ Heat Rate x Annual MW's displaced by AMGT (by fuel type) x Capacity Factor

Step 1.3: Fuel Cost Savings = Total Primary Energy Savings per year (by fuel type) x Fuel Price Forecast (by fuel type)

The AMGT will displace less efficient steam plants and lead to primary energy savings.



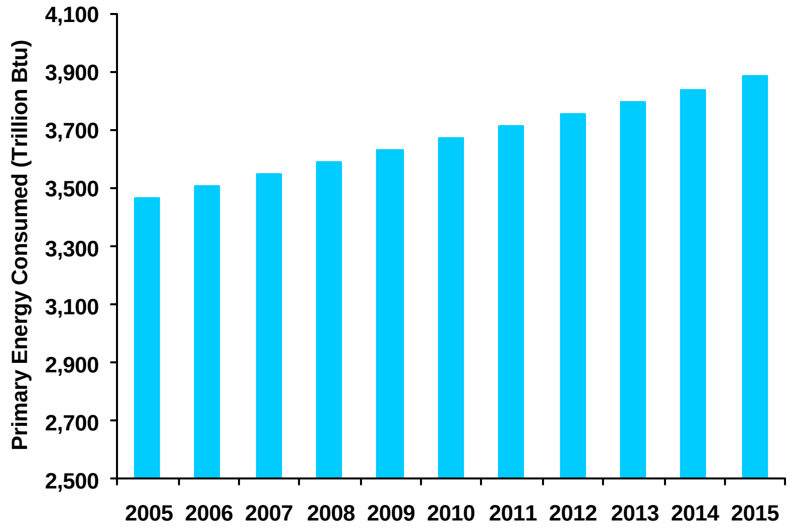
Displaced fuel mix: 60% natural gas, 24% coal, 16% oil.

Although natural gas consumption will increase, there will be a net saving in primary energy.

Without AMGT, primary energy consumption will continue to rise with load growth.

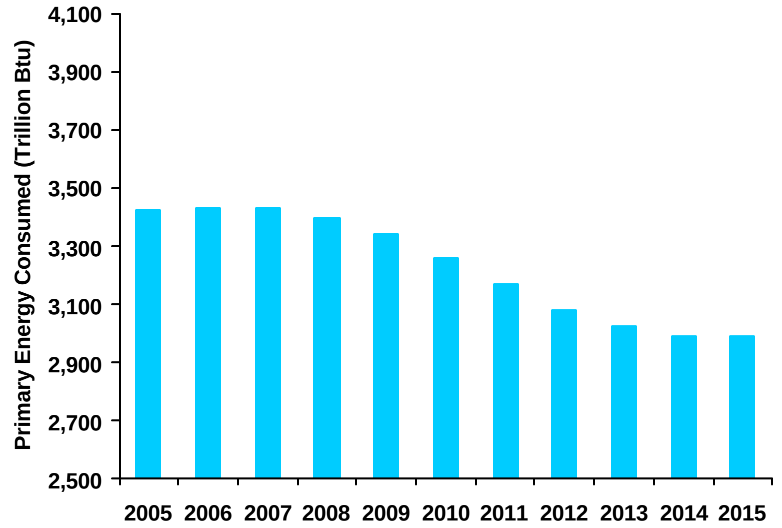
Without AMGT

Primary Energy Consumed by Plants That Would Have Been Displaced by AMGT

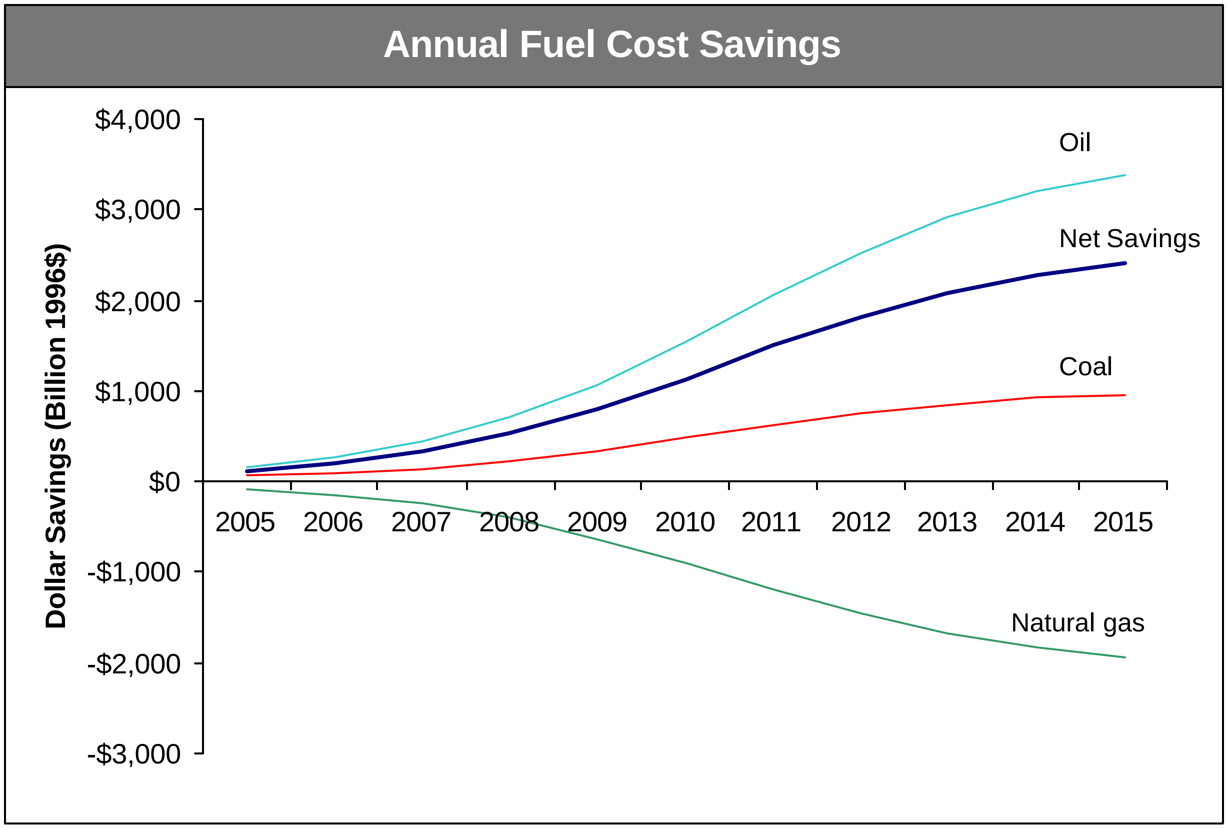


With AMGT

Primary Energy Consumption With AMGT



The primary energy savings would lead to fuel cost reductions, mostly from oil.



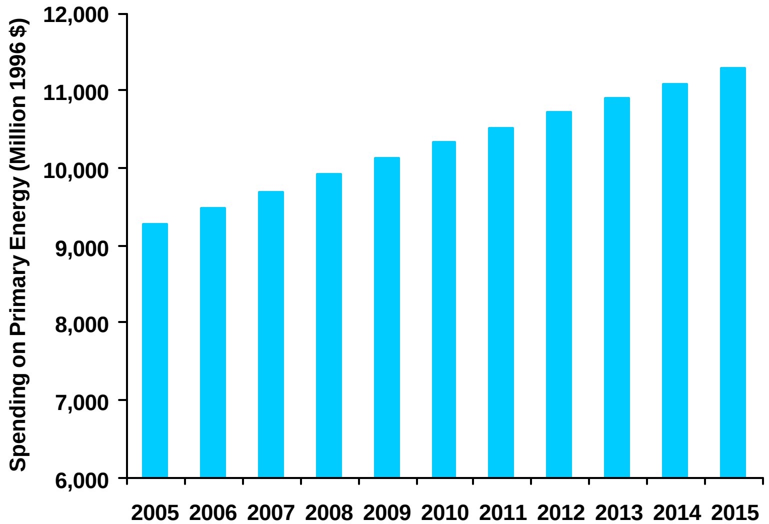
Fuel cost projections from Annual Energy Outlook 1998, DOE EIA.

The energy cost savings from oil and coal would offset the increased spending on natural gas.

The improved efficiency of AMGT over existing technologies and plants will slow down the increase in spending on fuels as less energy will be consumed each year.

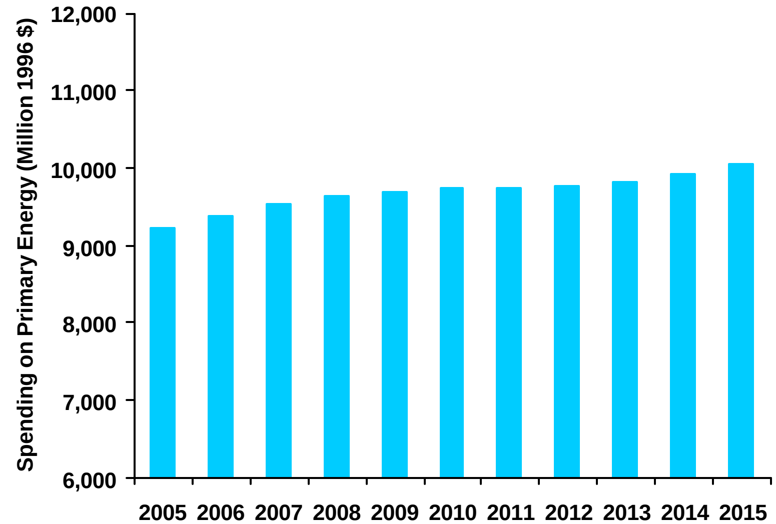
Without AMGT

Spending on Primary Energy by Plants That Would Have Been Displaced by AMGT



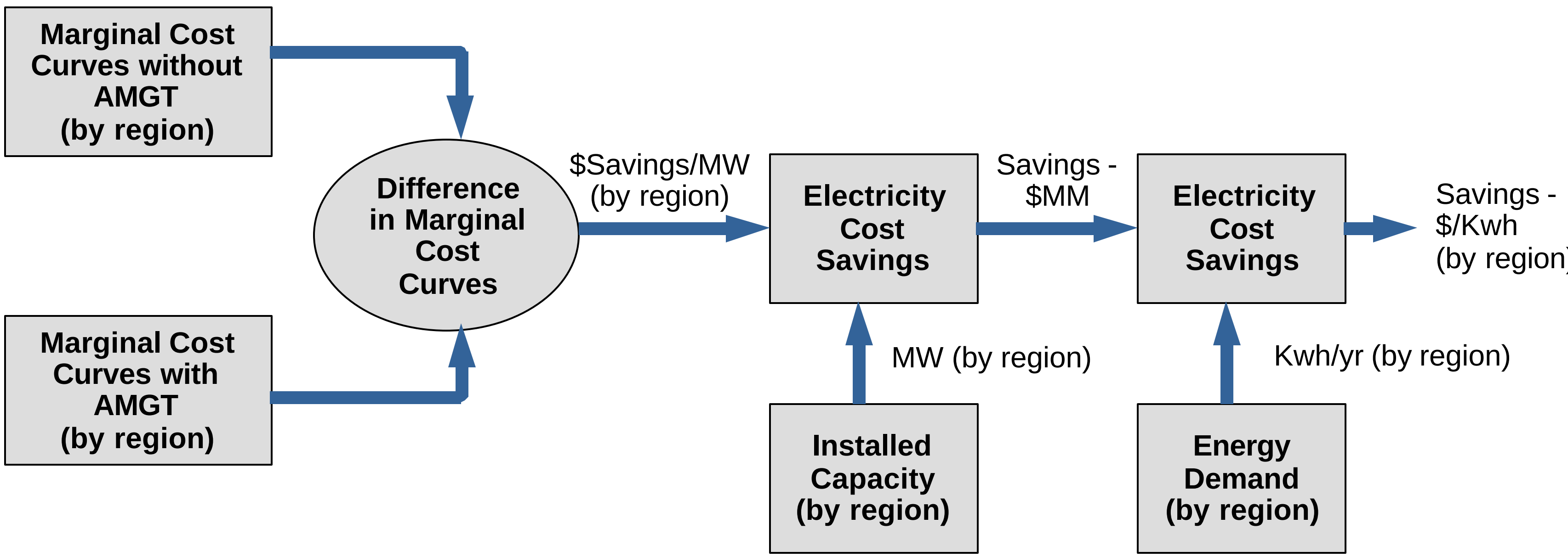
With AMGT

Spending on Primary Energy with AMGT



There will still be a slight annual increase as AMGT will displace less costly fuels (on a per Btu basis) with a more costly fuel (i.e., natural gas).

The second step of the public benefits analysis requires three calculations to calculate electricity cost reductions.



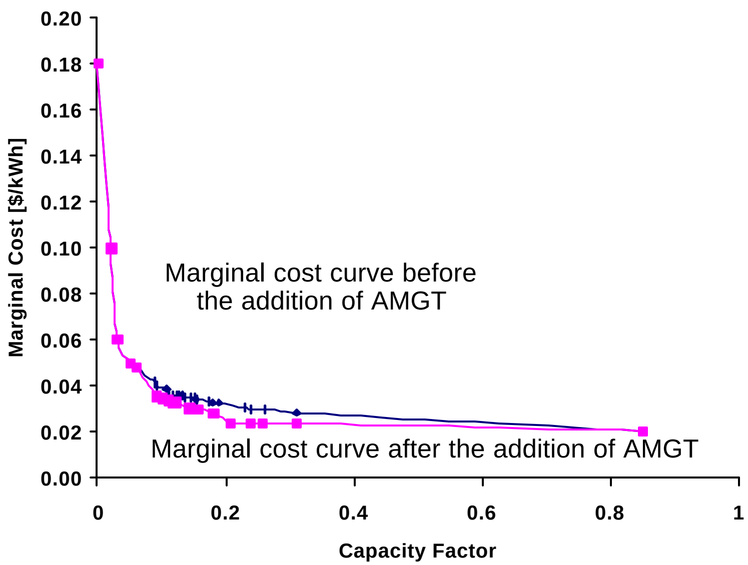
Step 2.1: Calculate the difference between the area under the margin cost curves with and without AMGT. This yields savings on $/MW basis by region.

Step 2.2: Multiply $/MW savings by installed capacity = $ savings by region

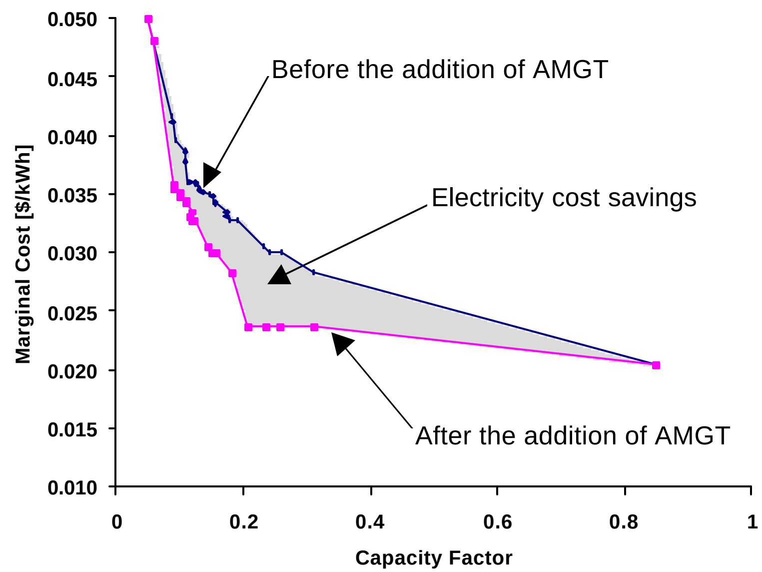
Step 2.3: Divide $ savings by demand (Kwh) = $ savings/Kwh

The adoption of AMGT would lead to lower marginal cost of electricity production which in turn would result in electricity cost savings.

Marginal Cost of Generation in California



Marginal Cost of Generation in California (expanded)



The electricity costs savings is the difference in the area under the two marginal cost curves.

The electricity costs savings for California, ERCOT and New England were computed from the marginal cost curves.

	Current Situation			AMGT Savings		
	Installed Capacity[1] (MW)	Energy Demand[1] (MM kWH)	Current Cost of Electricity[2] (¢/kWh)	Electricity Cost Savings ($MM)	Electricity Cost Savings (¢/kWh)	% Electricity Cost Savings
California	44,076	227,876	9.54	$137	0.06	0.6
New England	22,501	109,144	10.46	$305	0.28	2.7
Texas	54,005	244,981	6.20	$465	0.19	3.1
Average			8.73		0.18	2.1

[1] Average of summer and winter capacity, NERC Reliability Assessment 1997-2006 and Inventory of Power Plants in the United States as of January 1, 1997, DOE EIA.
[2] Electric Power Annual 1997 Vol. II, average of industrial, commercial, and residential sectors.

$$\text{Electricity Cost Savings (\$)} = \left(\int \begin{array}{c}\text{marginal}\\ \text{cost curve}\\ \text{before AMGT}\end{array} - \int \begin{array}{c}\text{marginal}\\ \text{cost curve}\\ \text{after AMGT}\end{array} \right) \text{X installed capacity}$$

$$\text{Electricity Cost Savings (¢/kWh)} = \begin{array}{c}\text{electricity}\\ \text{cost}\\ \text{savings (\$)}\end{array} \Big/ \text{energy demand}$$

Electricity cost savings for the rest of the country is estimated from the California, ERCOT and New England experience.

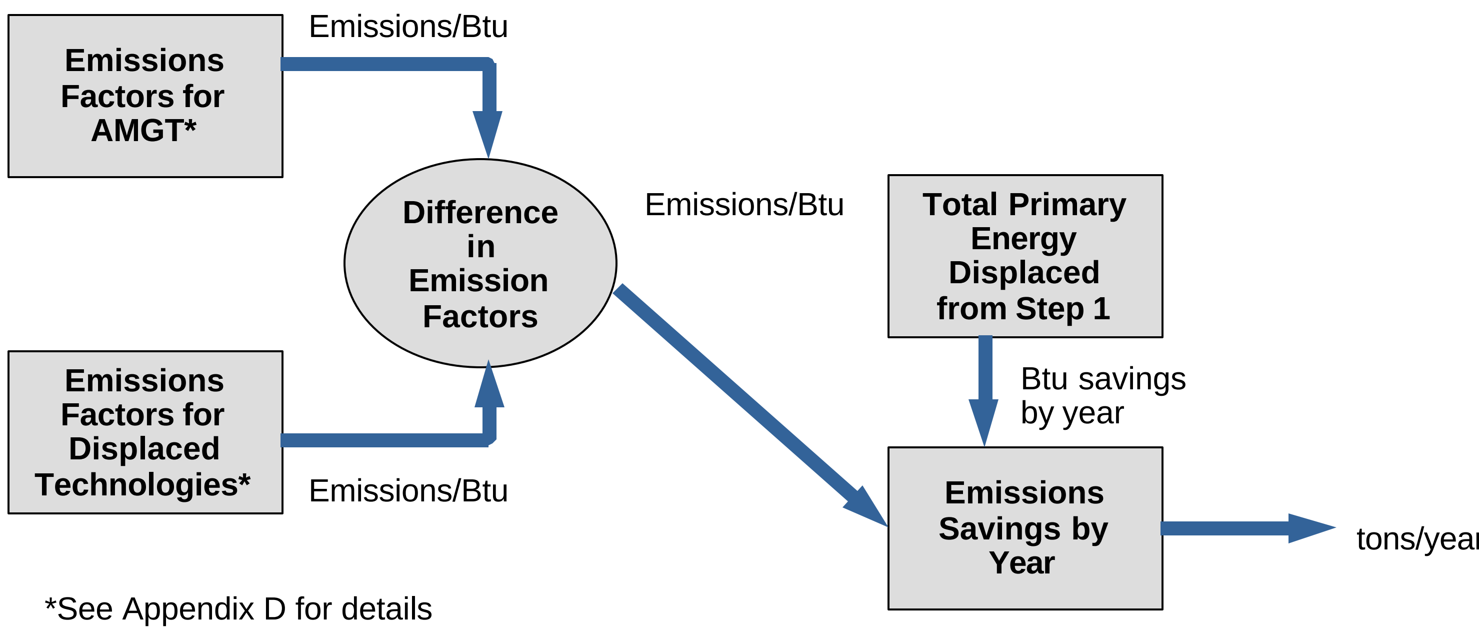
	Installed Capacity[1] (MW)	AMGT Addition (% of installed capacity)	Current Energy Demand[1] (MM kWH)	Current Cost of Electricity[2] (¢/kWh)	Projected Savings from AMGT (¢/kWh)	% Electricity Cost Savings
California[3]	44,076	14	227,876	9.54	0.06	0.63
New England[3]	22,501	19	109,144	10.46	0.28	2.7
Texas[3]	54,005	40	244,981	6.20	0.19	3.1
WSCC (less CA)	87,496	2	394,289	5.90	0.01	0.17
MAPP	31,109	2	149,368	5.90	0.01	0.17
SPP	71,729	32	305,272	5.00	0.14	2.8
MAIN	52,744	8	237,014	4.10	0.03	0.73
ECAR	104,312	2	537,623	6.50	0.01	0.15
SERC	151,698	0	604,492	6.60	0.002	0.03
FRCC	9,314	50	177,792	7.30	0.32	4.4
MAAC	57,093	5	246,668	7.00	0.03	0.43
New York	32,319	13	131,936	11.13	0.13	1.2

1 Average of summer and winter capacity, NERC Reliability Assessment 1997-2006 and Inventory of Power Plants in the United States as of January 1, 1997, DOE EIA.
2 Electric Power Annual 1997 Vol. II, average of industrial, commercial, and residential sectors.
3 Savings from AMGT calculated directly from regional analyses.

Calculating electricity cost savings in this manner represents the most optimistic scenario for electricity consumers.

- As AMGT is added the marginal cost curve will be adjusted as this analysis predicts.
- In a perfectly efficient market with pure competition where commodity pricing is accessible or transparent to customers, the electricity cost savings would be passed on to the consumer.
- In practice, however, consumers will not have clear access to commodity pricing and may have already entered into long-term contracts. This will allow some of these electricity cost savings to be taken as profits by generation companies and power marketers, particularly in the short term.
- Therefore, in a reasonably efficient market with competitive electricity cost, savings will be split between consumers, generation companies and power marketers.
- Understanding exactly how this division of savings will occur is difficult to analyze.

The third step in the public benefits analysis requires two substeps to calculate emissions reductions.

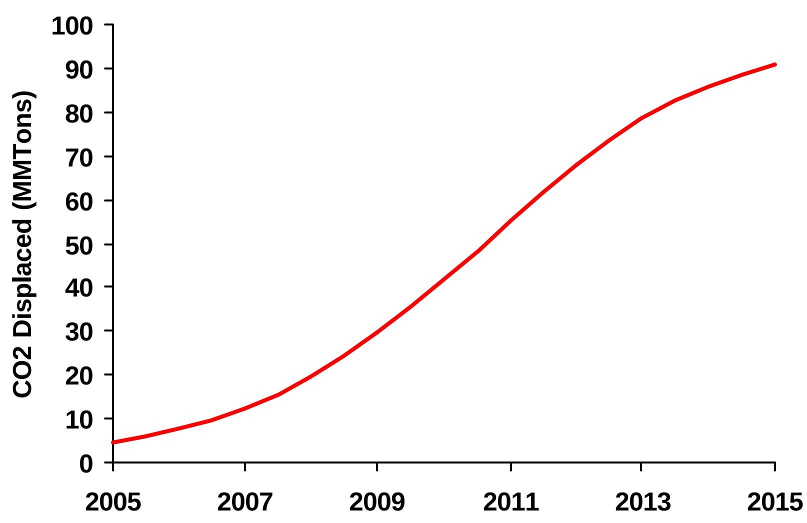


Step 3.1: Calculate Δ emissions factors (emissions factors of displaced technologies - emissions factors for AMGT)

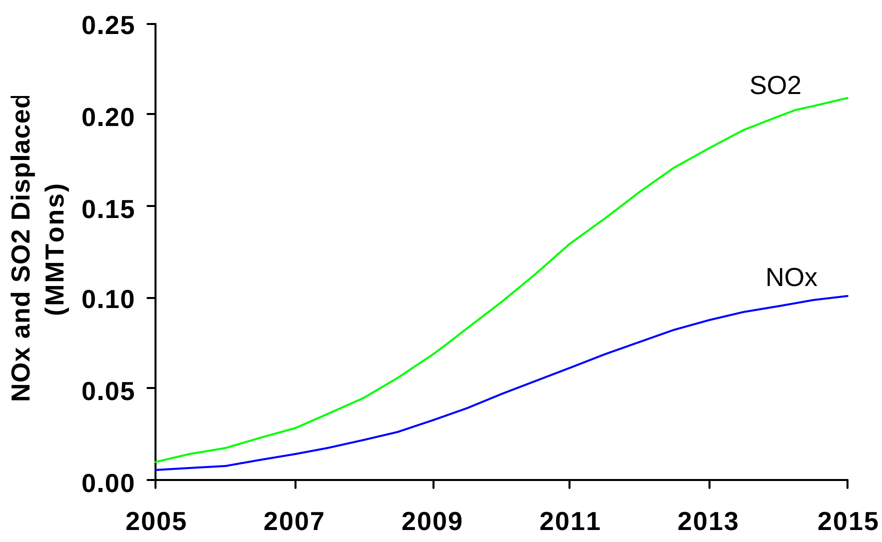
Step 3.2: Total emission savings (tons/year) = Δ emissions factor x Btu savings per year

The adoption of AMGT will lead to air emission savings in CO_2, NO_x and SO_x.

Annual CO_2 Savings



Annual NO_x and SO_2 Savings

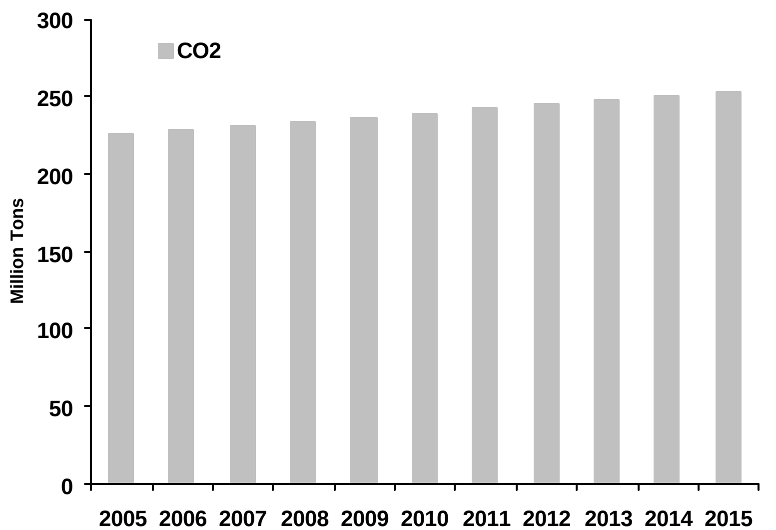


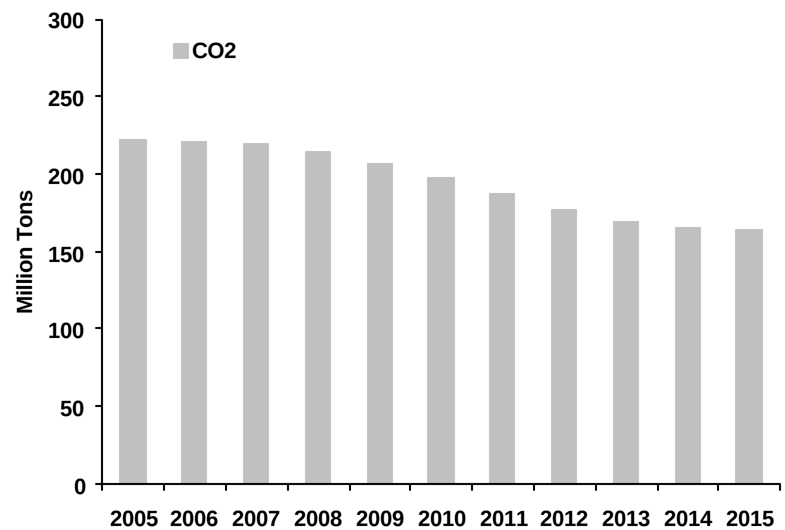
Source: AMGT emissions from manufacturer surveys

Significant emission savings especially in CO_2 can be achieved with the adoption of AMGT. The majority of the SO_2 savings is from the displacement of coal plants.

CO_2 emissions from intermediate load plants will continue to increase with load growth.

Without AMGT	With AMGT
CO_2 Emissions from Plants that would have been Displaced by AMGT	CO_2 Emissions with AMGT



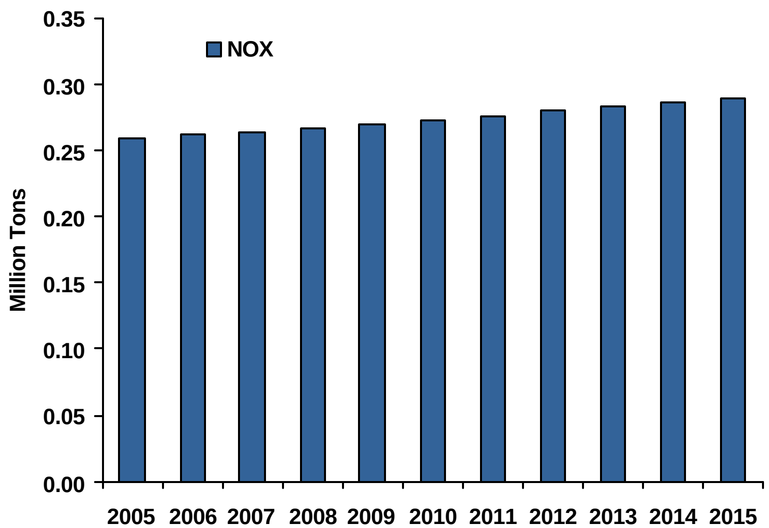


Source: AMGT emissions from manufacturer surveys

The adoption of AMGT would reduce the NO_x emissions from intermediate load plants by half.

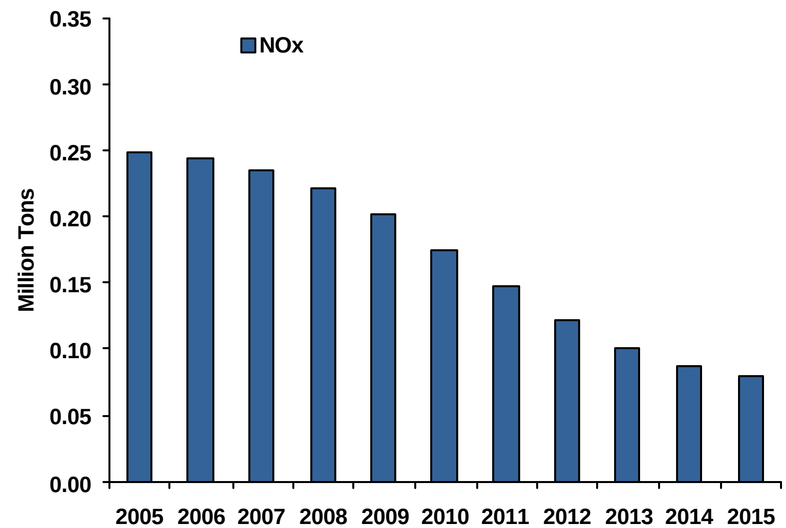
Without AMGT

NO_x Emissions from Plants that would have been Displaced by AMGT



With AMGT

NO_x Emissions with AMGT

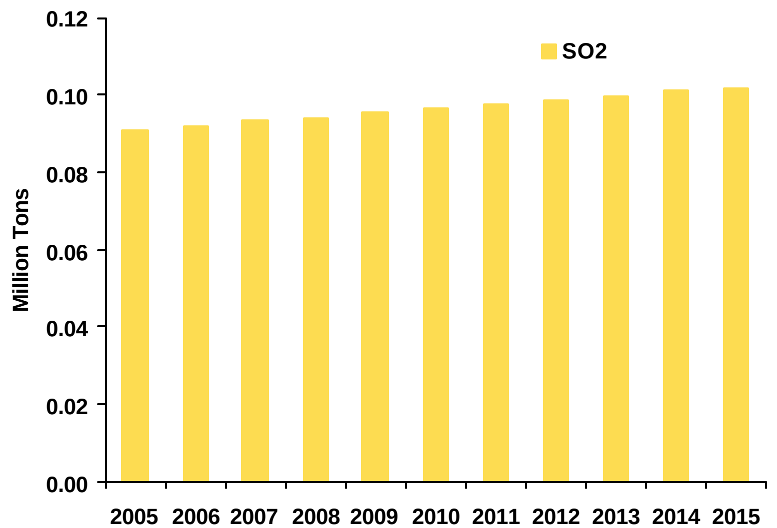


Source: AMGT emissions from manufacturer surveys

The savings on SO_2 would be the most dramatic as AMGT replaces oil and coal plants.

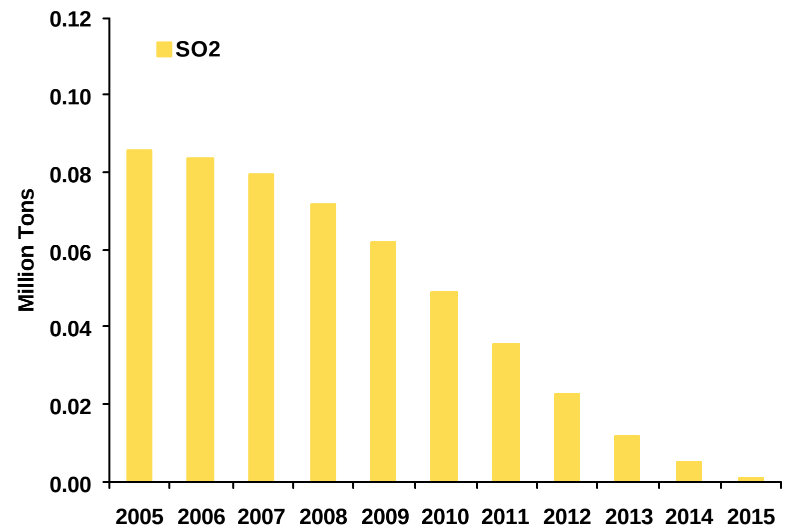
Without AMGT

SO_2 Emissions from Plants that would have been Displaced by AMGT



With AMGT

SO_2 Emissions with AMGT

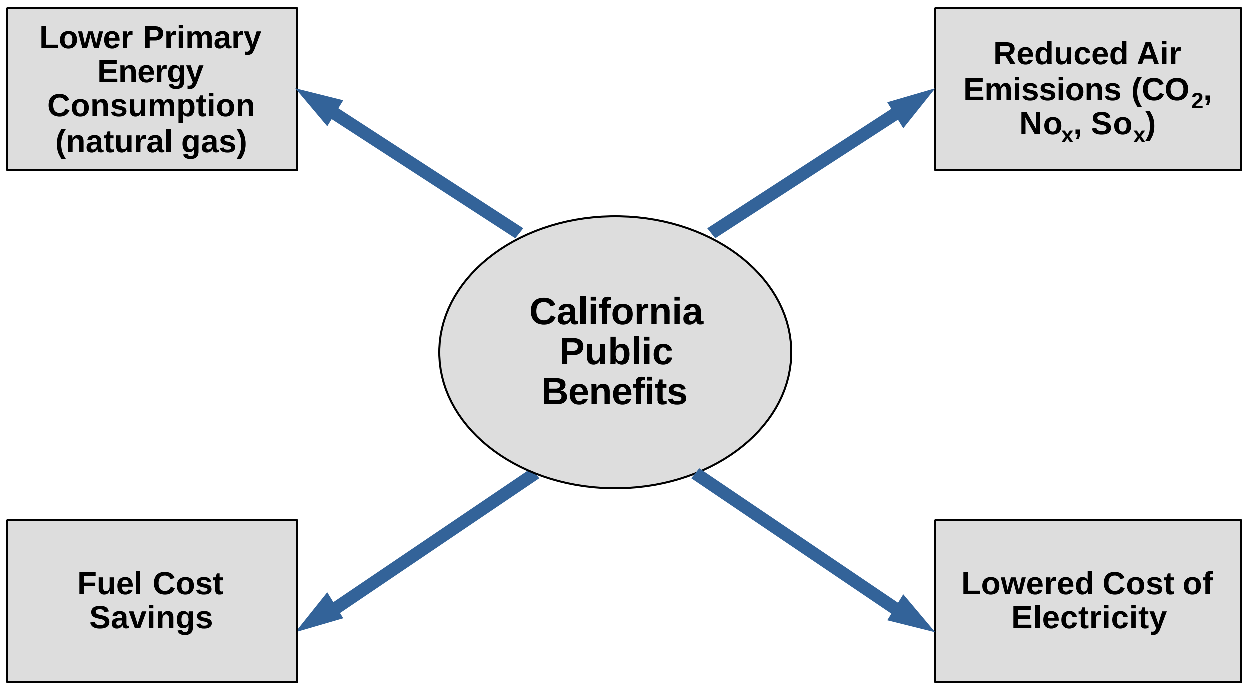


Source: AMGT emissions from manufacturer surveys

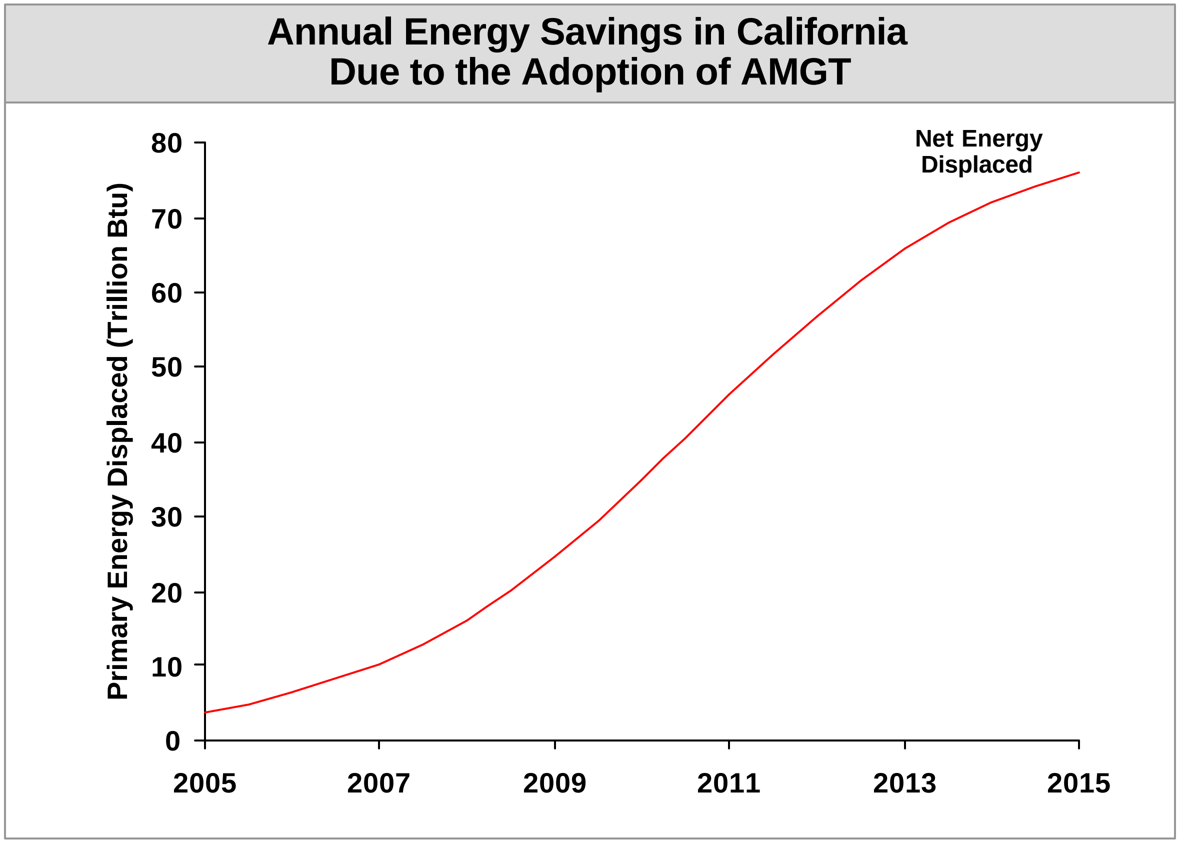
The cumulative energy and emissions savings could be substantial especially in the later years when AMGT becomes widely adopted.

	Cumulative Savings in the US		
	2005	**2010**	**2015**
Primary Energy (Trillion BTU)	40	1,100	4,900
Fuel Costs Savings (MM 1996$)	63	1,600	6,900
CO_2 (MMTons)	4.5	120	490
SO_x (MMTons)	0.005	0.13	0.55
NO_x (MMTons)	0.01	0.27	1.1

In the fourth step of the analysis; energy, fuel, emissions and electricity cost savings are presented for California.



The AMGT will be displacing the older, less efficient natural gas plants in California resulting in primary energy savings.

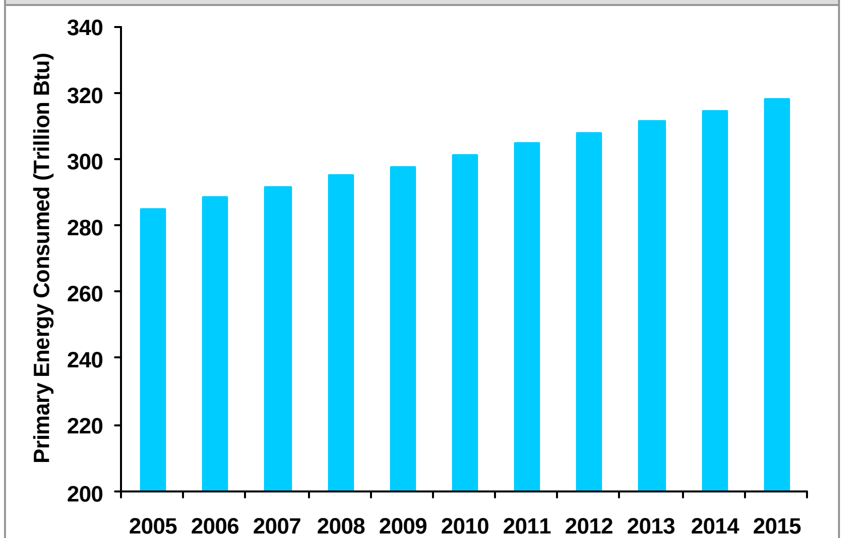


Displaced fuel mix in California: 100% natural gas.

Without the AMGT, primary energy consumption from intermediate load plants will continue to rise with load growth.

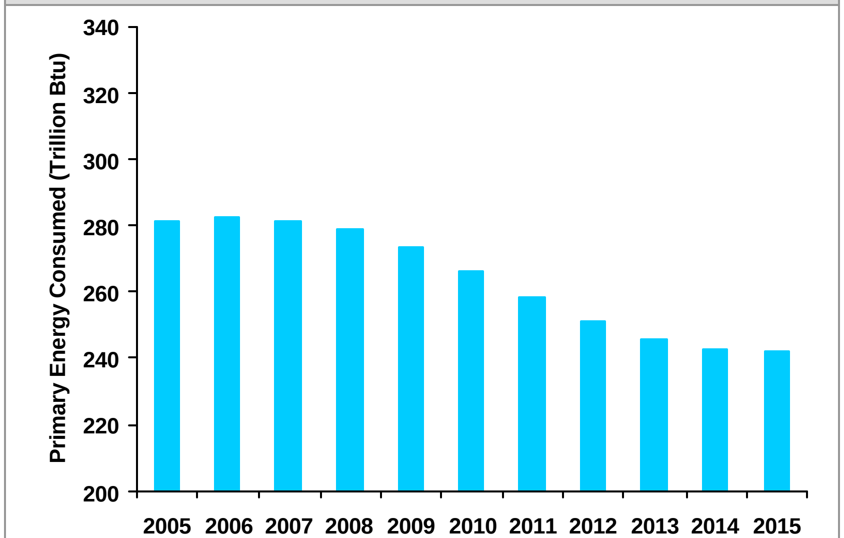
Without AMGT

Primary Energy Consumed by Plants that would have been Displaced by AMGT

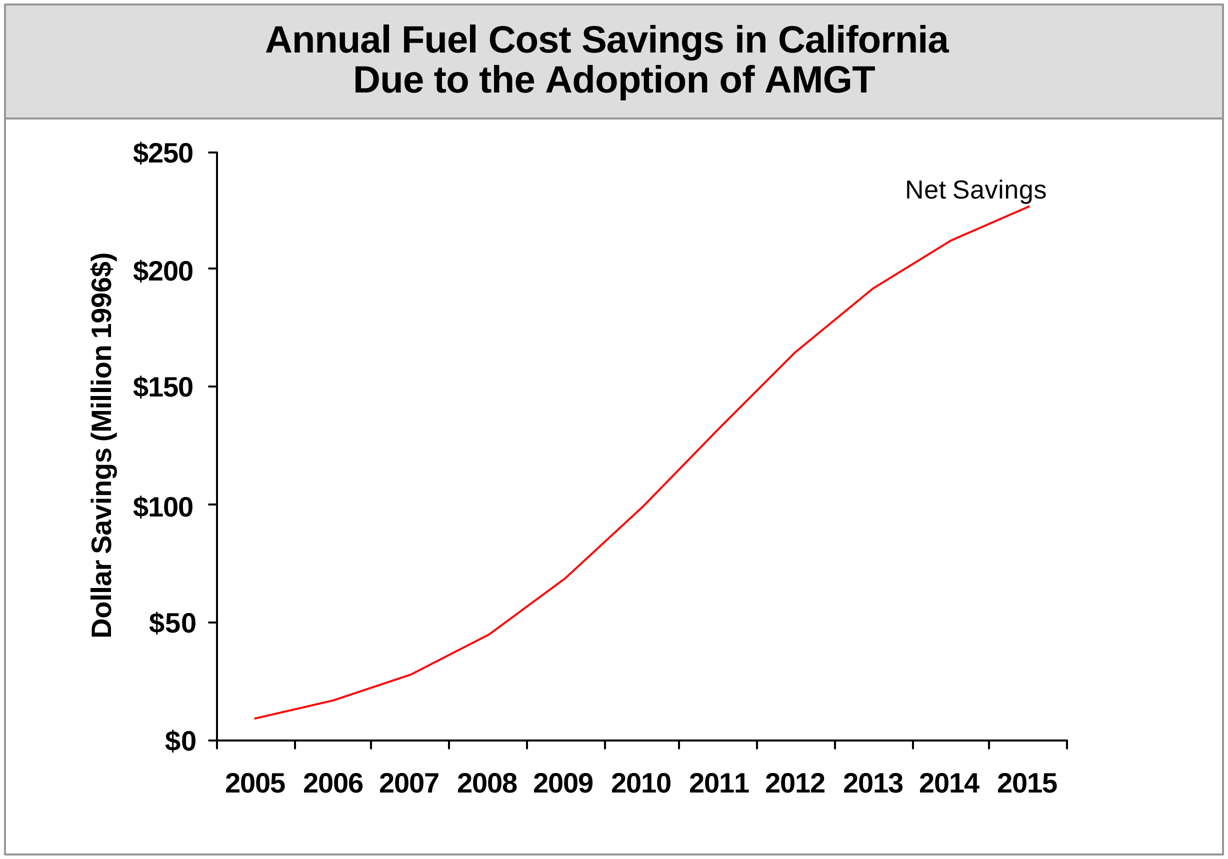


With AMGT

Primary Energy Consumption with AMGT



The primary energy savings would lead to fuel cost savings.

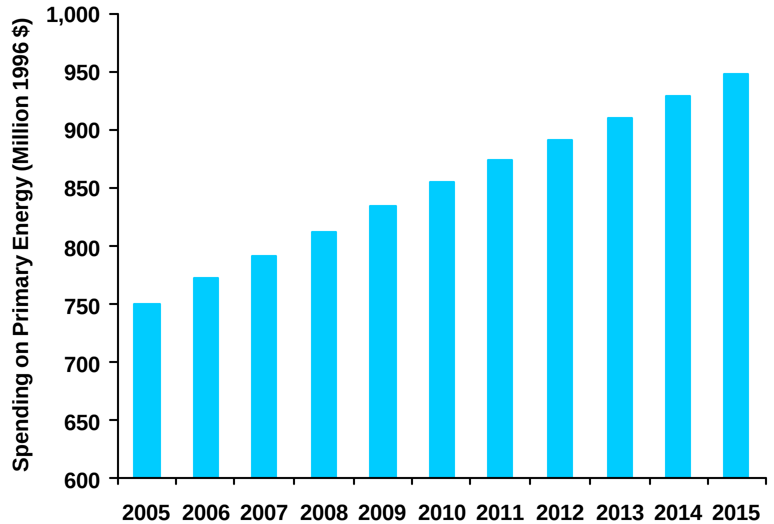


Fuel cost projections from Annual Energy Outlook 1998, DOE EIA.

Natural gas consumption reductions would directly lead to lower fuel cost spending.

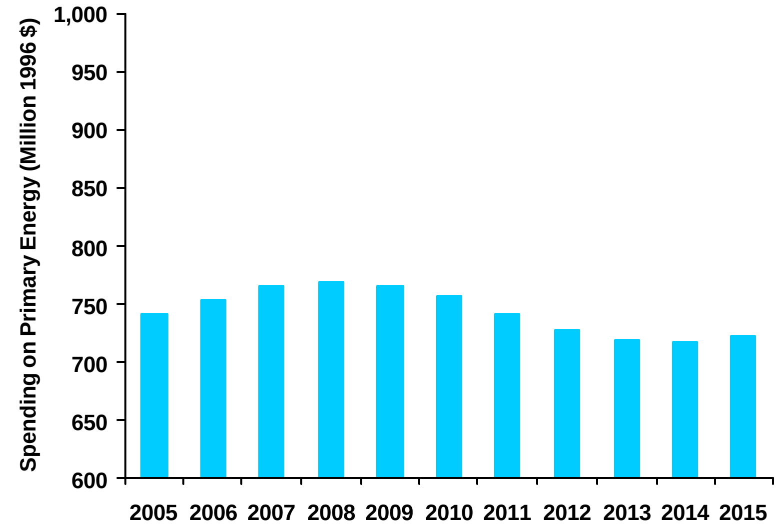
Without AMGT

Spending on Primary Energy by Plants that would have been Displaced by AMGT



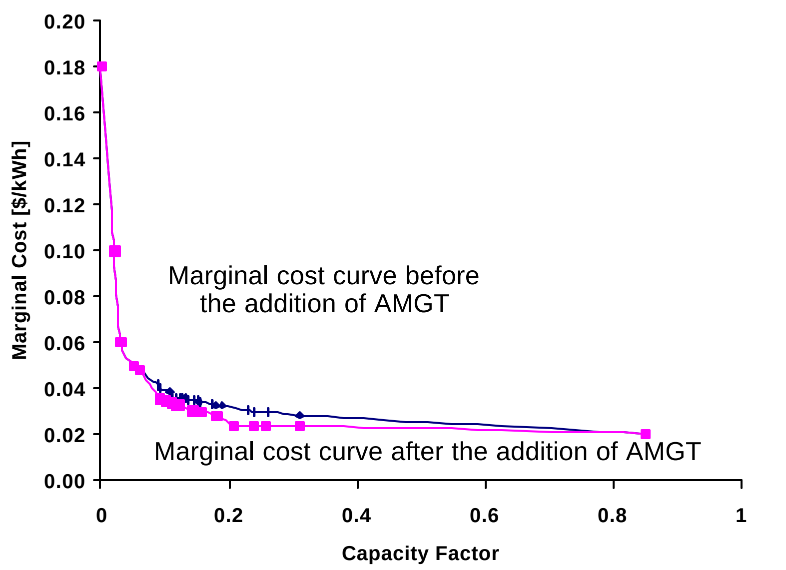
With AMGT

Spending on Primary Energy with AMGT

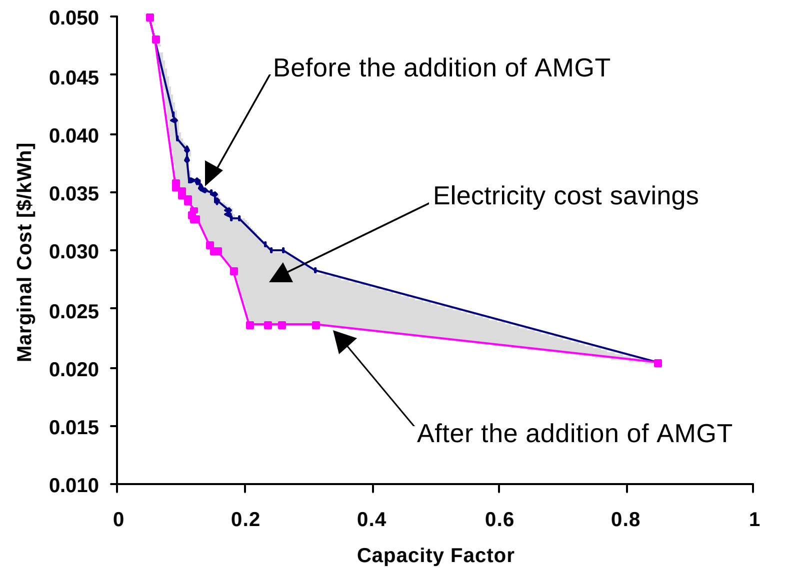


The adoption of AMGT would lead to lower marginal cost of electricity production resulting in electricity costs reductions.

Marginal Cost of Generation in California



Marginal Cost of Generation in California (expanded)



The electricity costs savings is the difference in the area under the two marginal cost curves.

The electricity costs savings for California was computed from the marginal cost curves.

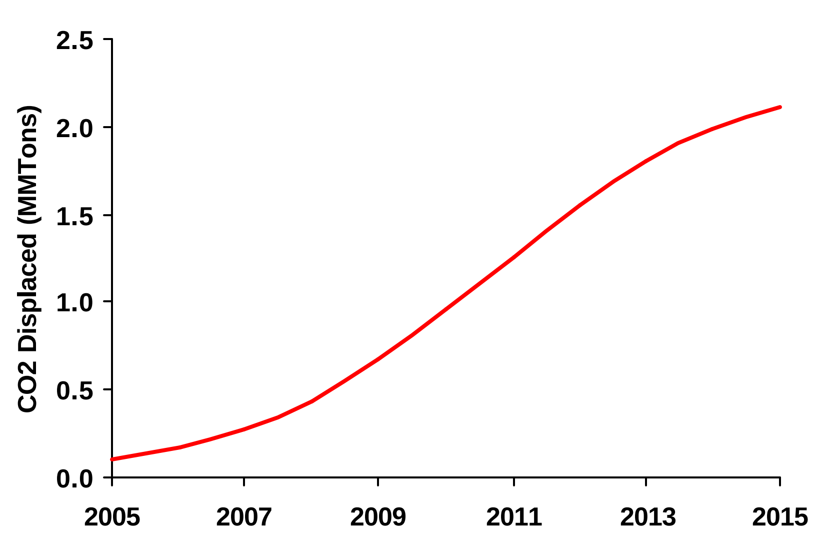
	Installed Capacity[1] (MW)	AMGT Addition (% of installed capacity)	Current Energy Demand[1] (MM kWH)	Current Cost of Electricity[2] (¢/kWh)	Projected Savings from AMGT (¢/kWh)	% Electricity Cost Savings
California	44,076	14	227,876	9.54	0.06	0.63

[1] Average of summer and winter capacity, NERC Reliability Assessment 1997-2006 and Inventory of Power Plants in the United States as of January 1, 1997, DOE EIA.
[2] Electric Power Annual 1997 Vol. II, average of industrial, commercial, and residential sectors.

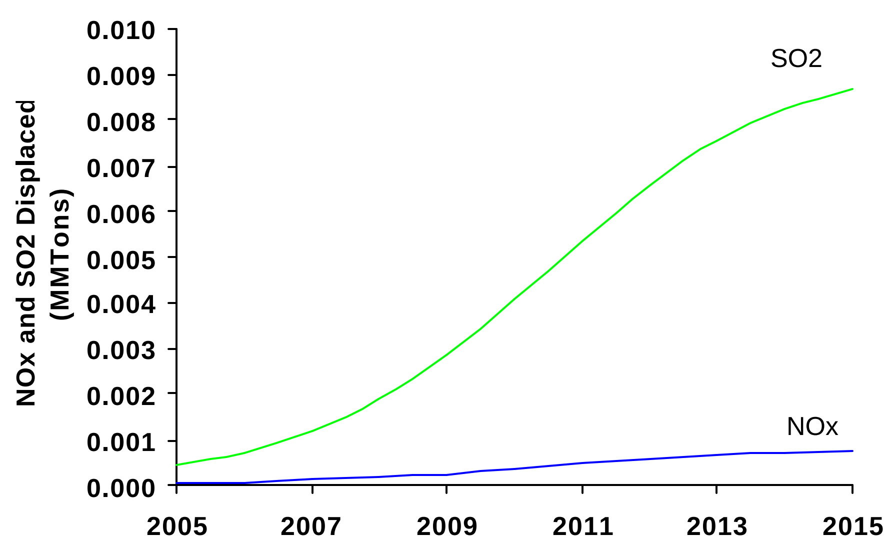
On average, the adoption of AMGT would result in a 0.63% reduction in the cost of electricity.

The adoption of AMGT will lead to air emission savings in CO_2, NO_x and SO_x.

Annual CO_2 Savings



Annual NO_x and SO_2 Savings

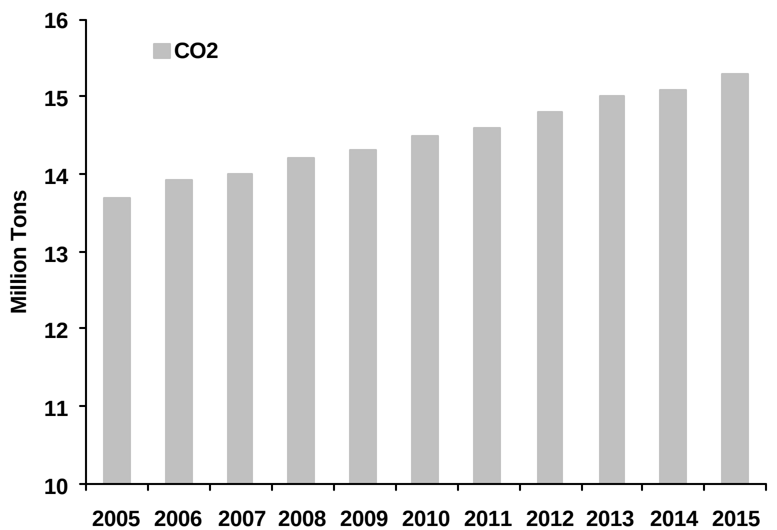


Source: AMGT emissions from manufacturer surveys

Without AMGT, CO_2 emissions will continue to increase from plants that would have been displaced by AMGT.

Without AMGT

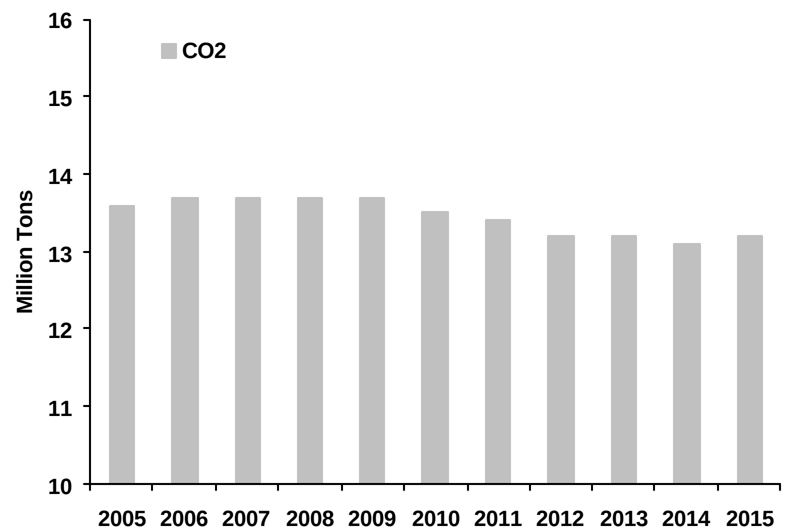
CO_2 Emissions from Plants that would have been Displaced by AMGT



Source: AMGT emissions from manufacturer surveys

With AMGT

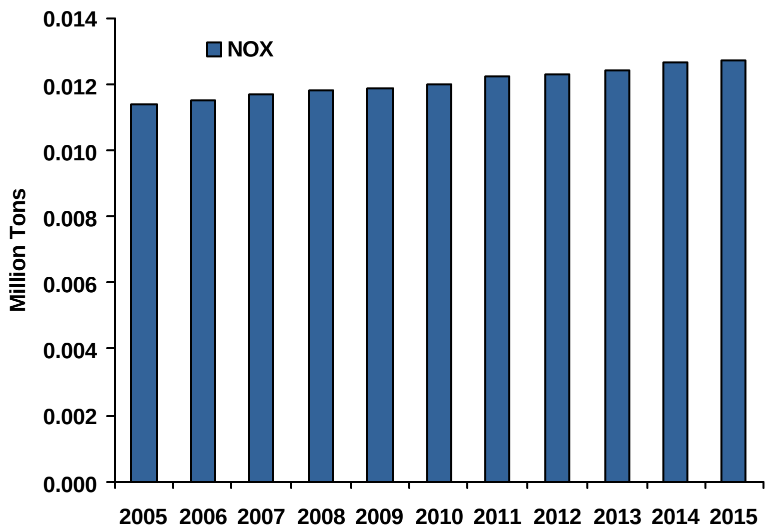
CO_2 Emissions with AMGT



The adoption of AMGT would reduce the NO_x emissions from intermediate load plants by half.

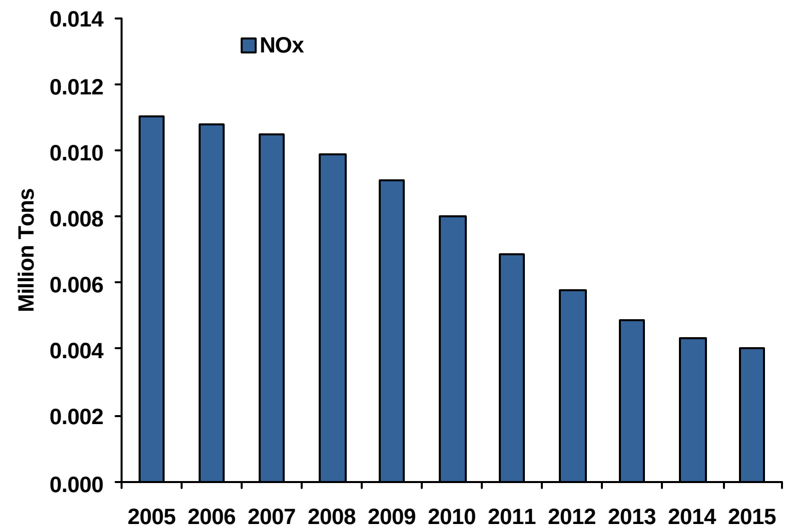
Without AMGT

NO_x Emissions from Plants that would have been Displaced by AMGT



With AMGT

NO_x Emissions with AMGT

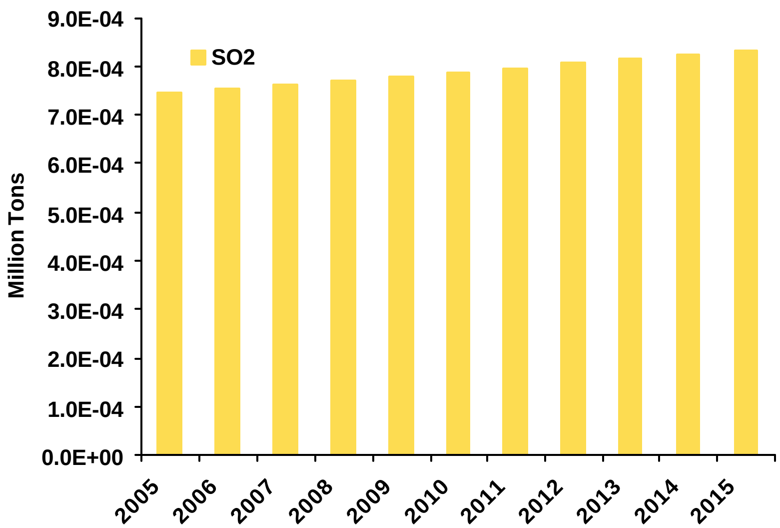


Source: AMGT emissions from manufacturer surveys

The reduction in primary energy consumption would account for most of the SO_2 emission savings.

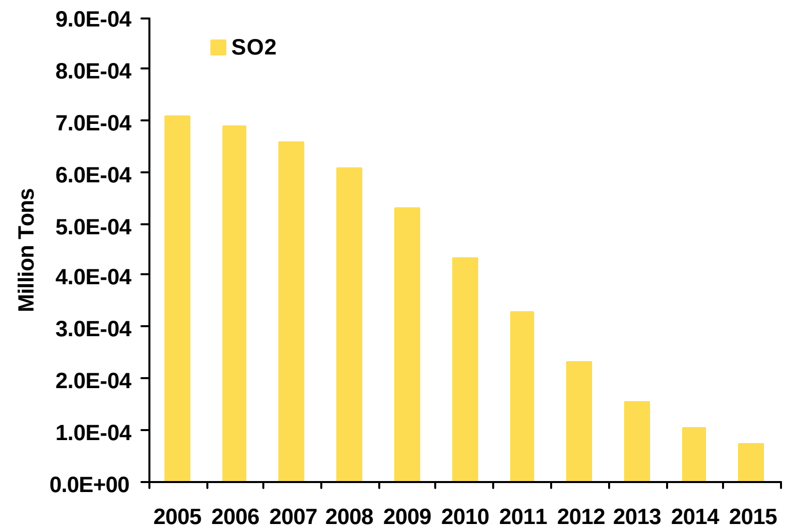
Without AMGT

SO_2 Emissions from Plants that would have been Displaced by AMGT



With AMGT

SO_2 Emissions with AMGT



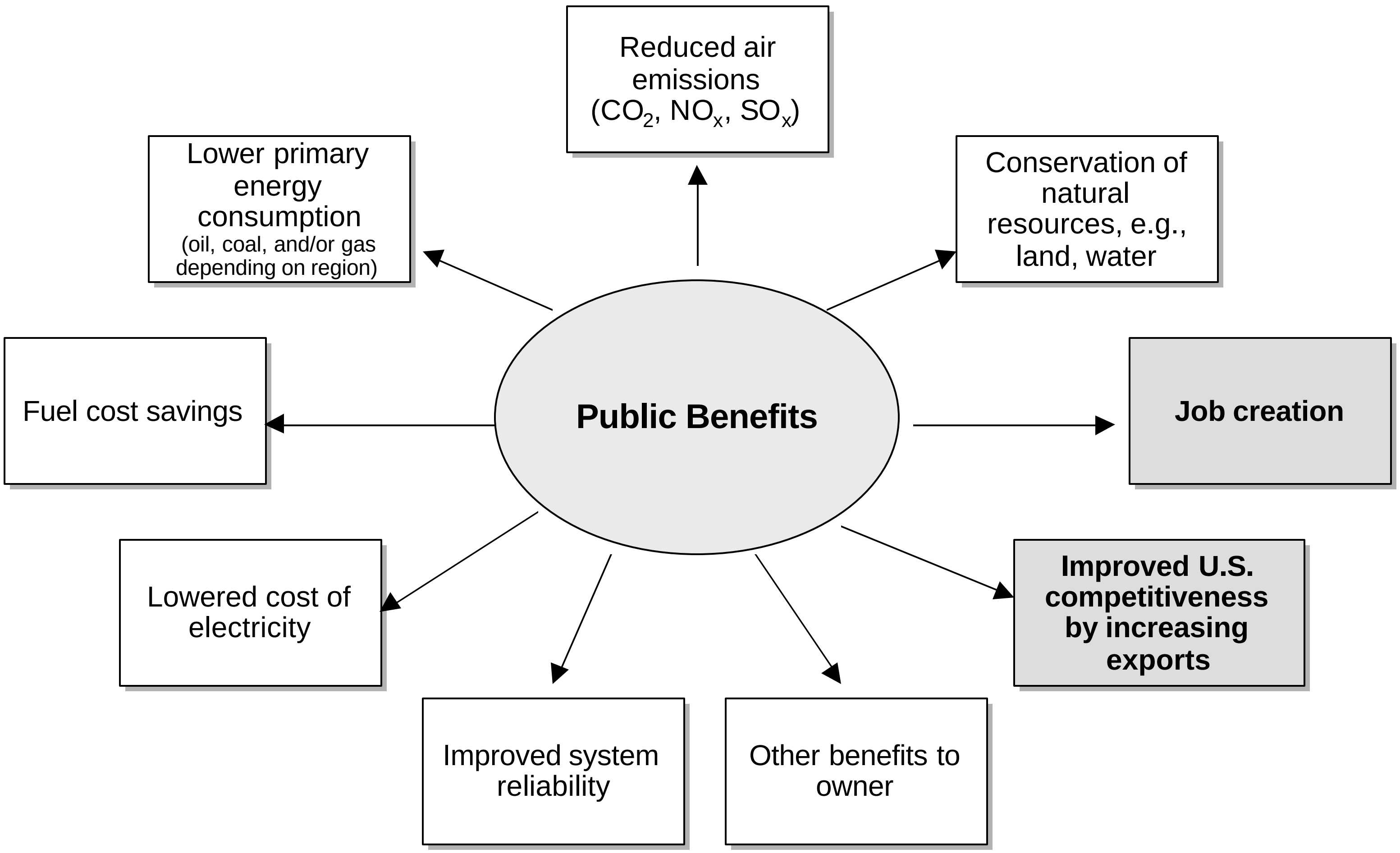
Source: AMGT emissions from manufacturer surveys

There is relatively little emissions savings in California, as compared to the rest of the US, since AMGT is replacing existing natural gas plants.

	Cumulative Savings in California		
	2005	**2010**	**2015**
Primary Energy (Trillion BTU)	3.7	96	413
Fuel Costs Savings (MM 1996$)	9.7	267	1,195
CO_2 (MMTons)	0.099	2.6	11
SO_x (MMTons)	0.00004	0.00098	0.0042
NO_x (MMTons)	0.0004	0.011	0.048

The reduced consumption in primary energy is the main driver for emissions savings.

In Step 5 of the public benefits analysis, job creation and export potential are estimated.

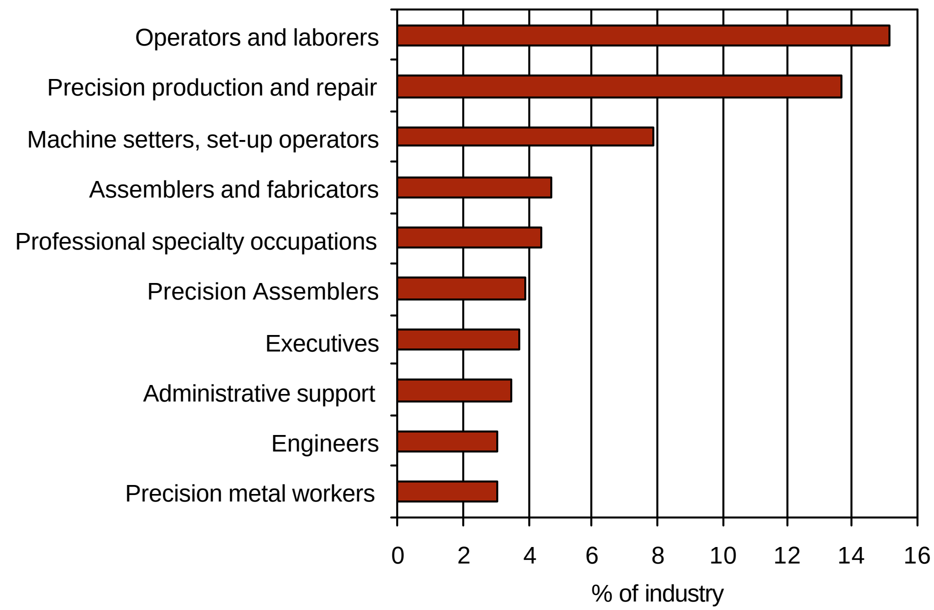


The production of AMGT will lead to job creation in the U.S.

Salaries of Turbine Industry Employees

- Historically, each employee in the turbines and turbine generator sets manufacturing industry is responsible for $246,000 of shipments.*
- An annual production level of 8,000 MW of AMGT at $150/kW would result in the creation of 4,800 jobs in the turbine manufacturing industry.
- The majority of these jobs would be directly related to the production process, e.g., operators and precision assemblers.
- At an annual compensation of $44,000 per employee*, this translates to a payroll of $215 million.

Job Categories in the Turbine Industry

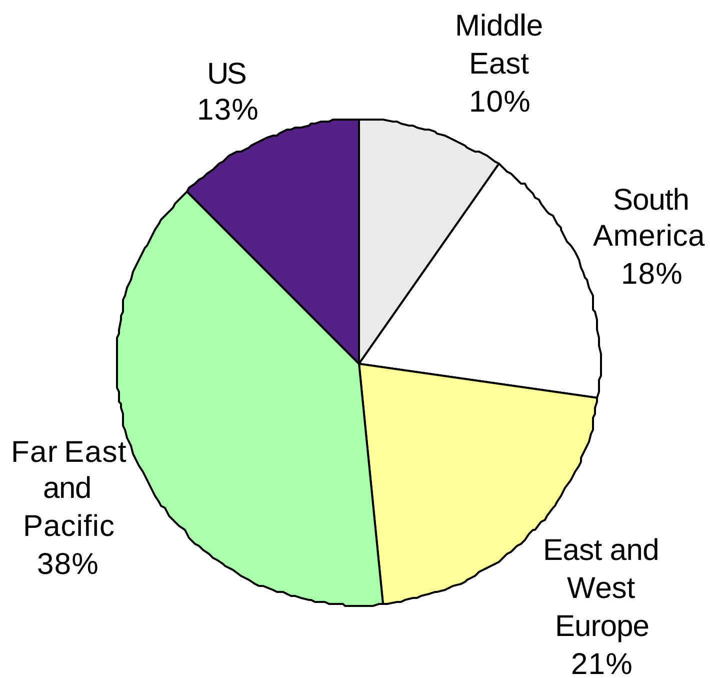


*: Average of 1993-1995 data.
Sources: Manufacturing USA, 4th edition; 1994 and 1995 Annual Survey of Manufacturers, Statistics for Industry Groups and Industries, U.S. Dept. of Commerce, Economics and Statistics Administration, Bureau of Census. SIC code 3511: turbine and turbine generator sets.

Source: Bureau of Labor Statistics, 1996 Industry-Occupation Matrix, industry Code 413510

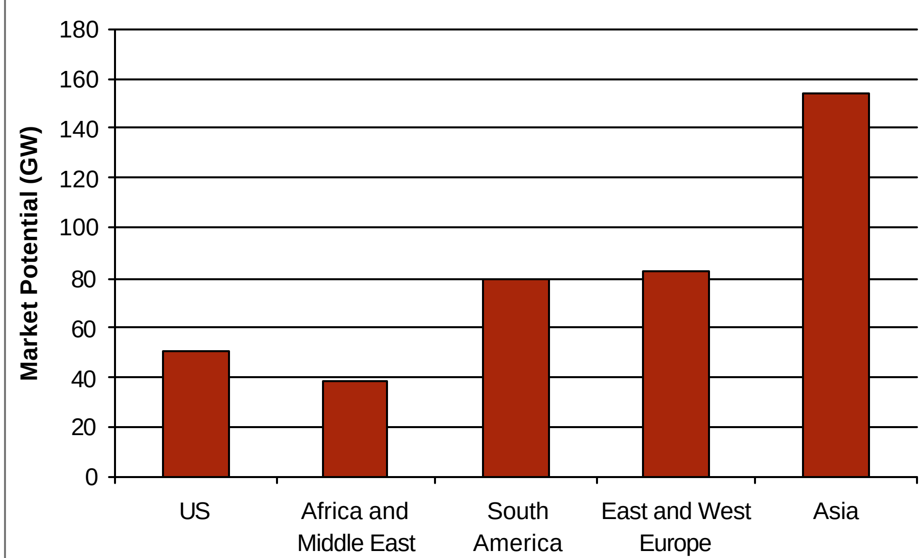
Based on historical trends of gas turbine sale worldwide, the global AMGT market potential could be 400 GW.

World Gas Turbine Orders and Installations by MW



Gas turbine sales in 1996. Overall market size:37GW.
Source: McCoy

AMGT Global Market Potential (2005–2015)

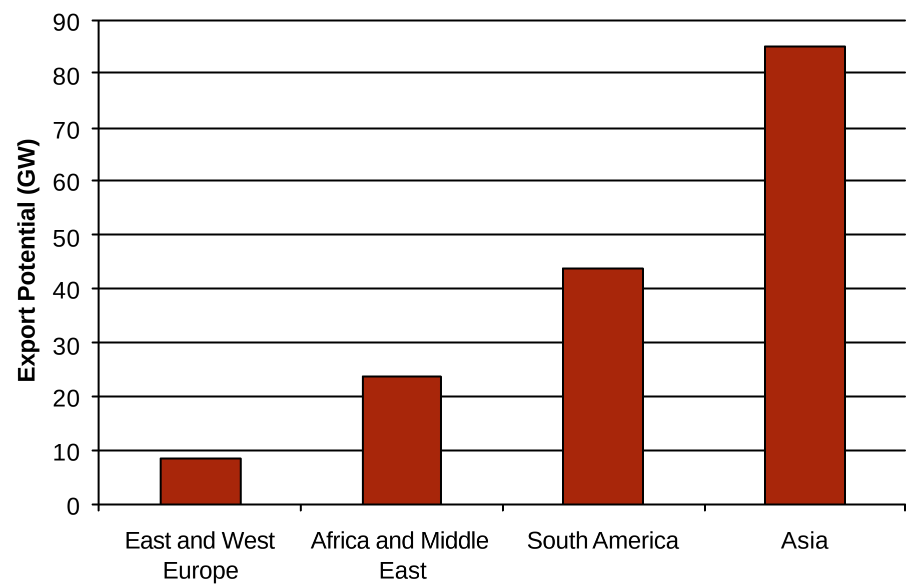


U.S. turbine manufacturers would capture a portion of the global market leading to AMGT exports, potentially $24 BN.

AMGT Global Market Share

- Historically, US manufacturers[1] have accounted for 55% of gas turbine sales in the 30–150 MW range worldwide[2].
- Applying the historical US market shares to different regions would result in an export potential of 160 GW, or $24BN.

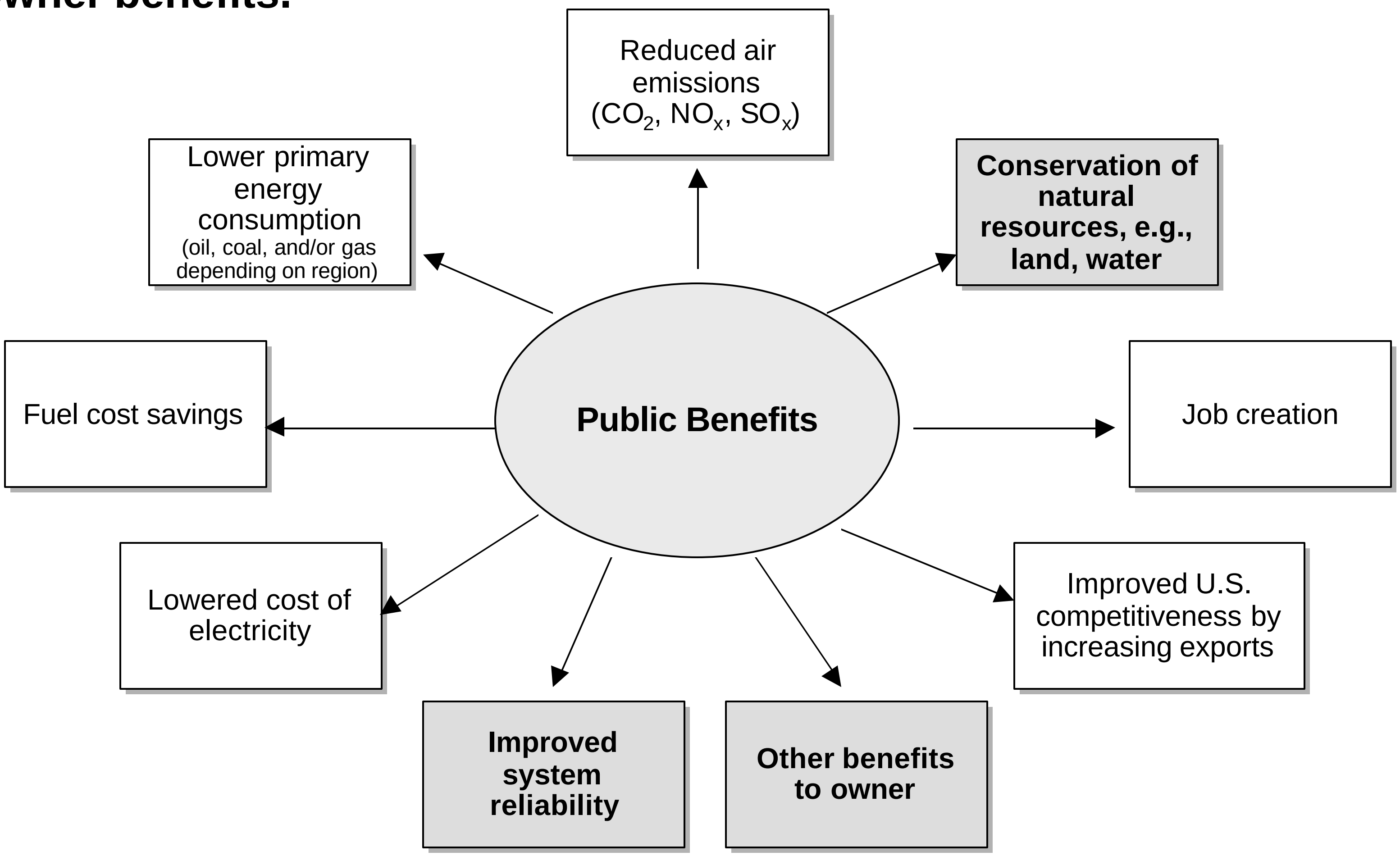
AMGT Export Potential by Region (2005–2015)



1 For this analysis, GE, Stewart & Stevenson, and Westinghouse are considered US turbine manufacturers.

2 Source: 1997 Gas Turbine World Handbook

In the last step, additional AMGT benefits were examined including conservation of natural resources, improved T&D reliability, and other owner benefits.



The use of gas turbines will also lead to land and water resources savings from the steam plants they displace.

		Gas Turbine*	Steam Plant^	Percent Reduction
Land (acres)		5–15	25–45	60% - 90%
Water	Service & Plant Water (mgd)	1–2	0.5–1	
	Cooling Tower Makeup Water (mgd)	0–8	12–15	
	Waste Water Discharge (mgd)	1–8	8–14	
	Overall (mgd)	2–18	20 - 30	30% - 90%

*: Includes SCGT and GTCC (100MW -250MW) .
^: Gas, oil and coal (180MW-225MW).

Note: Calculating the total benefits from AMGT is difficult as:
- ➜ The actual performance from AMGT is unknown
- ➜ There is a wide variation on land and water use by fuel and by geographic location
- ➜ It is not clear if these savings in land will be realized as the disposition and value of the land is unknown.

The AMGT may lead to more savings over the GTCC and SCGT depending on the technology deployed in the AMGT.

The size and flexibility of the AMGT could lead to benefits to the T&D system.

- Many of the standards and requirements set for ancillary services are based on current technology and resource mix. The quick start capability of the AMGT may lead to reduced requirements for ancillary services.
- Its mid-sized range would cause AMGT to be dispersed throughout the grid rather than centrally located. This could lead to:
  - Increased reliability
  - Improved power quality in terms of voltage stability, and
- The AMGT could be used to relieve grid congestion and reduce the burden on the T&D system.

The size and flexibility of the AMGT may result in additional benefits to the power plant owners.

- Its quick start capability could allow it to better respond to the power market. The size of the AMGT may facilitate the marketing of power from the plant as well. It may be easier to market 100 MW from an AMGT plant than to market 1,000 MW from a GTCC.
- Its flexibility may allow owners to participate in both energy markets as well as ancillary services markets.
- There could reduced risk for generation owners.
  - Size and modularity allows smaller amounts of equity to be incrementally invested in one project at one location or in one region.
  - Rapid installation time reduces construction risk.
- Deployment of AMGT may allow for standardization of operations and O&M.

Table of Contents

Each of the AMGT applications will put different emphasis on design and operating requirements.

Application Classes	Application Requirements
Intermediate Load	Daily
	Weekly
	Seasonal
Peaking	Daily
Repowering	Feedwater Preheating
	Full Brownfield
Ancillary Services	Regulation, AGC, Voltage Support
	Spinning Reserve
	Non-Spinning Reserve
	Replacement/Operating Reserve, Black Start
	Transmission Congestion
Cogen	High T/E Ratio
	Low T/E Ratio
Green Power	Dedicated Biomass
	Cycle Hybrid
	Project Integration

Design requirements that impact cycling are most important to daily peaking and intermediate load.

Design and Operating Requirements	Intermediate Load			Peaking	Repowering	
	Daily	Weekly	Seasonal		Feedwater Preheating	Full Brown Field
Efficiency (electrical)	◕	◕	◕	◔	◔	◕
Hot day output & efficiency	○	○	◑	○	○	○
No load/part load efficiency	◑	◔	○	○	○	○
Capital cost	◕	◕	◕	●	◕	◕
O&M cost	◕	◕	◕	◑	◕	◕
Life cycle cost due to cycling	◕	◑	◔	◕	○	○
Start-up time	◕	◑	○	◕	◔	○
Ramp rate	◑	◔	○	◕	○	○
Scalability	○	○	○	◑	◑	◑
Modularity	○	○	○	◑	◑	◑
Fuel flexibility	◔	◔	◔	◔	◔	◔
RAMD	◑	◑	◑	◑	◔	◑
Waste heat	○	○	○	○	●	◔
Emissions	◕	◕	◕	◕	◕	◕
Water usage	◔	◔	◔	◔	◔	◔
Noise	○	○	○	○	○	○
Footprint	○	○	○	○	◕	◕

Low ○ ◔ ◑ ◕ ● High

← Importance →

Capital cost, O&M cost, scalability and waste heat are some of the primary requirements for cogen applications.

Operating Requirements	Cogen		Green Power		
	High E/T	Low E/T	Dedicated Biomass	Cycle Hybrid	Project Integration
Efficiency (electrical)	◕	◔	●	◔	◕
Hot day output & efficiency	○	○	○	○	○
No load/part load efficiency	◔	◓	○	◓	◕
Capital cost	◕	◕	●	●	◕
O&M cost	◕	◕	●	●	◕
Life cycle cost due to cycling	◓	○	○	○	○
Start-up time	◔	○	○	◔	◓
Ramp rate	◔	○	○	◔	◓
Scalability	◕	◕	◓	◕	◕
Modularity	◔	◔	◔	◔	◔
Fuel flexibility	◔	◔	●	◓	◔
RAMD	◓	◓	◓	◓	◔
Waste heat	◓	●	◓	○	○
Emissions	◕	◕	●	●	●
Water usage	○	○	○	◓	○
Noise	○	○	○	○	○
Footprint	◓	◔	◔	◔	◔

Low ○ ◔ ◓ ◕ ● High

← Importance →

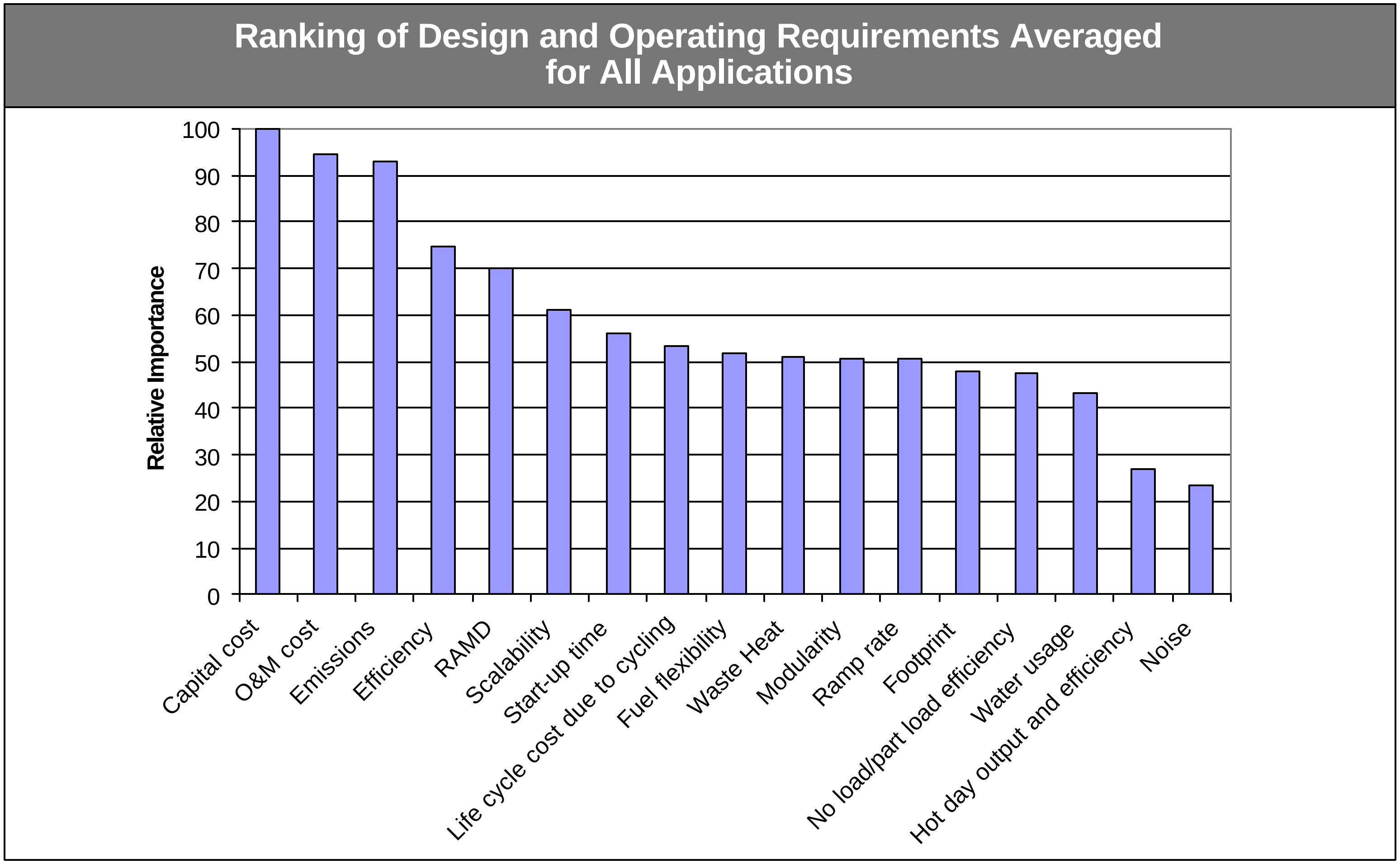
For ancillary services, the operability issues such as ramp rate, life cycle cost impact of cycling and start-up time become very important.

	Ancillary Services				
Operating Requirements	Regulation, AGC, Voltage Support	Spinning Reserve	Non-spinning Reserve	Replacement, Operating Reserves, Black starts	Transmission Congestion
Efficiency (electrical)	◕	◓	◔	◔	◓
Hot day output & efficiency	○	○	○	○	○
No load/part load efficiency	◕	◕	○	○	◔
Capital cost	◕	◕	●	●	◕
O&M cost	◕	◕	◕	◕	◕
Life cycle cost due to cycling	●	◕	◓	◔	◕
Start-up time	◔	◔	●	◕	◕
Ramp rate	●	◕	◕	◕	◓
Scalability	○	○	○	○	◔
Modularity	◓	◓	◓	◓	◓
Fuel flexibility	◔	◔	◔	◔	◔
RAMD	◓	◕	◕	◕	◓
Waste heat	○	○	○	○	○
Emissions	◕	◕	◔	◔	◓
Water usage	◔	◓	◓	◓	◔
Noise	○	○	○	○	○
Footprint	○	○	○	○	◓

Low ○ ◔ ◓ ◕ ● High

← Importance →

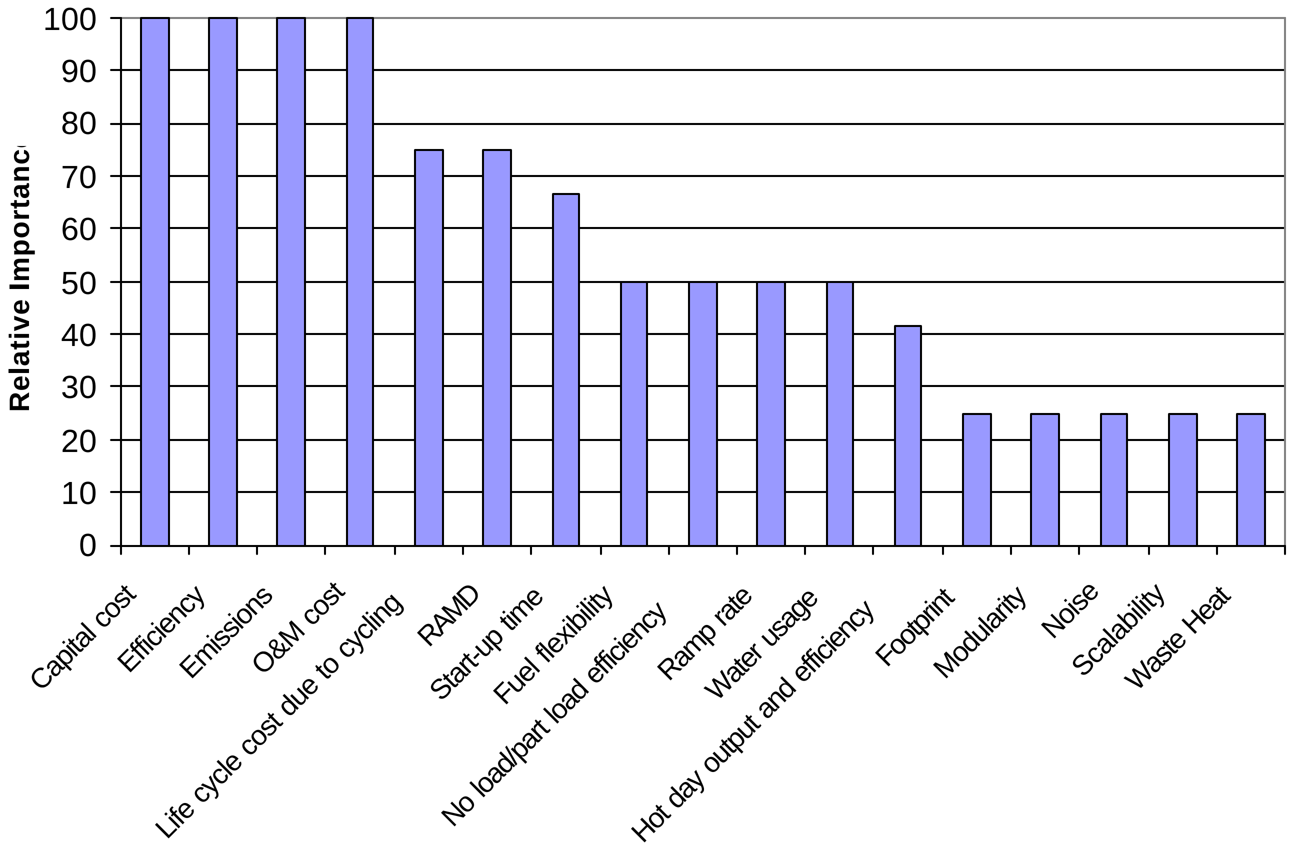
OEMs can either develop a product that suits all applications, or …



Combined design and operating requirements for intermediate load, cogen, peaking, repowering, green power, and ancillary services applications.

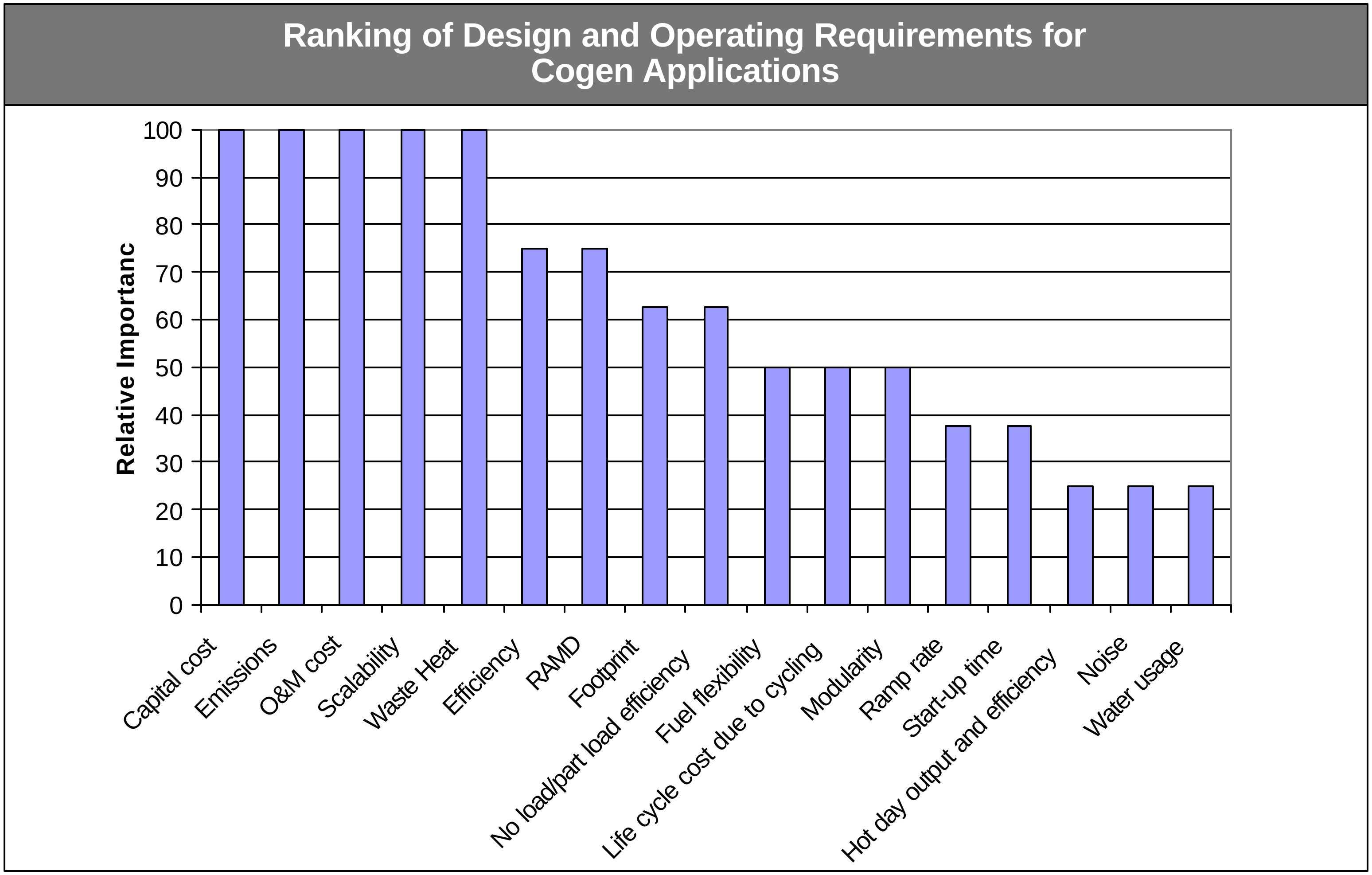
…develop a product that meets the needs of a single application.

Ranking of Design and Operating Requirements for Intermediate Load Applications



For example, capital cost, efficiency, emissions and O&M cost are the prime concerns for intermediate load.

Similarly, scalability and waste heat are unique requirements for cogen applications.



The technology development program for AMGT may be structured in a range of ways, from addressing all applications to focusing on a single application.

	Advantages	Disadvantages
Option 1: Develop technologies to address all applications	• Reap the public benefits of all applications, although public benefits for each application may be less than optimum	• More costly • Technology development effort becomes too diffuse • Technology may not be best-suited for the highest value applications
Option 2: Develop technologies for single application (for example: intermediate load)	• Maximizes the public benefits of a single, highest value application • Targeted, cost-effective development	• May not achieve public benefits potential of all applications
Option 3: Scale technology development program to address all applications	• Divides funding effort by the size of the benefit for each application • Should provide maximum public benefits • Development programs will be distributed over a wider range of technologies • Maximum technology development investments will be made in highest value applications	• Risks of program being too diverse • Technology funding may be inadequate to create desired result in lower priority areas • More difficult program to administer

Table of Contents

Manufacturers feel that government funding would be required to develop an AMGT product to mitigate technical and market risks.

- Most manufacturers agreed the aggregate performance goals of the AMGT were formidable, but attainable.
  - There would be significant technical development that would be required and associated technology risk.
  - To achieve these goals in a product would require a large investment and commitment on the part of both government and industry.
- Most manufacturers believe it is both necessary and desirable to pursue several different technology and cycle options appropriate to both frame and aero machines to achieve these goals.
- While many manufacturers are reluctant to discuss the performance targets of their planned products most manufacturers foresaw incremental efficiency improvement without government funding.
  - Research and development funding without government support would focus on current and near-term technology in such areas as combustion (i.e., emissions reductions) and thermal barrier coatings.

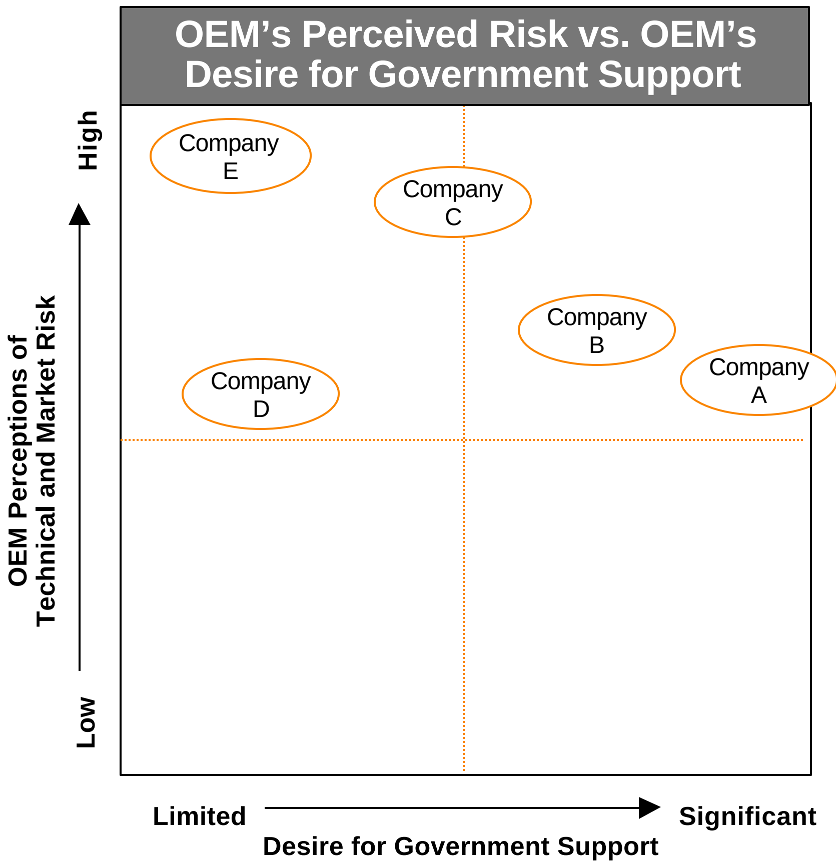
Manufacturers feel that government funding would be required to develop an AMGT product to mitigate technical and market risks. (cont.)

- Some see government funding as a means of accelerating current product plans but would not necessarily cause them to develop new product plans.
- Others felt they would not introduce a new product in this area without government funding.
- A few felt even with government funding they would delay product introduction until the needs of the new electricity industry were understood (2–3 years).
- In addition to technical risks, most gas turbine manufacturers see considerable market risks in developing a product when there are significant uncertainties associated with the restructuring of the electric utility industry.

Some manufacturers were hesitant about recommending a large demonstration program.

- Some manufacturers have already invested heavily in new, advanced products both for the aero and the power generation market.
  - These gas turbine manufacturers see considerable risks in developing a new product when there are significant uncertainties associated with the marketplace. All would be reluctant to commit to another large advanced technology program.
  - They expect to focus much of their efforts on these new products. Many of the advances in these products have been in efficiency and emissions, using more complex materials and cycles. These manufacturers feel there is still more R&D work to be done with these technologies to ensure they are successful and will not negatively impact reliability or operating costs.
- Some see political risk associated with an AMGT program, and feel it might be too soon after the ATS program.
  - An AMGT program could lead to confusion and doubt among policy and legislative stakeholders concerning the ATS program.
  - Unlike the ATS program, an AMGT program may not have the full support of all the manufacturers.
  - The AMGT program might be perceived as being a means to strengthen weaker competitors.
- Several manufacturers proposed sponsoring the development of underlying technology rather than a large demonstration program.

While most agreed there are significant technical and market risk, there was disagreement on the need for a program and how that program should be structured.



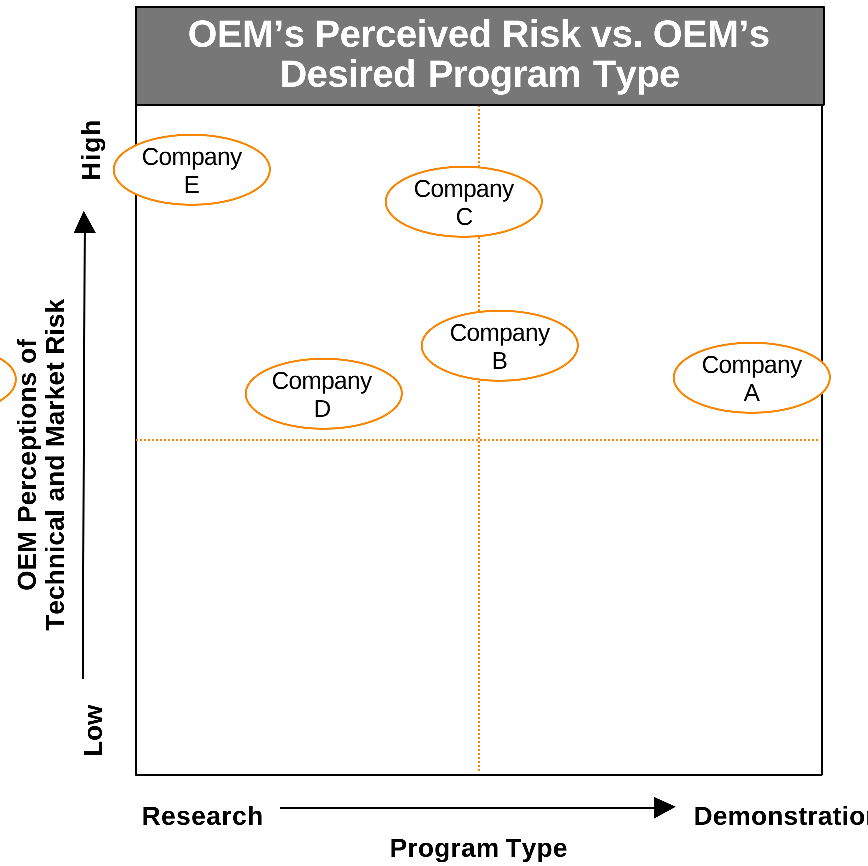


Table of Contents

Arthur D. Little has identified four development and demonstration program options to support AMGT product development.

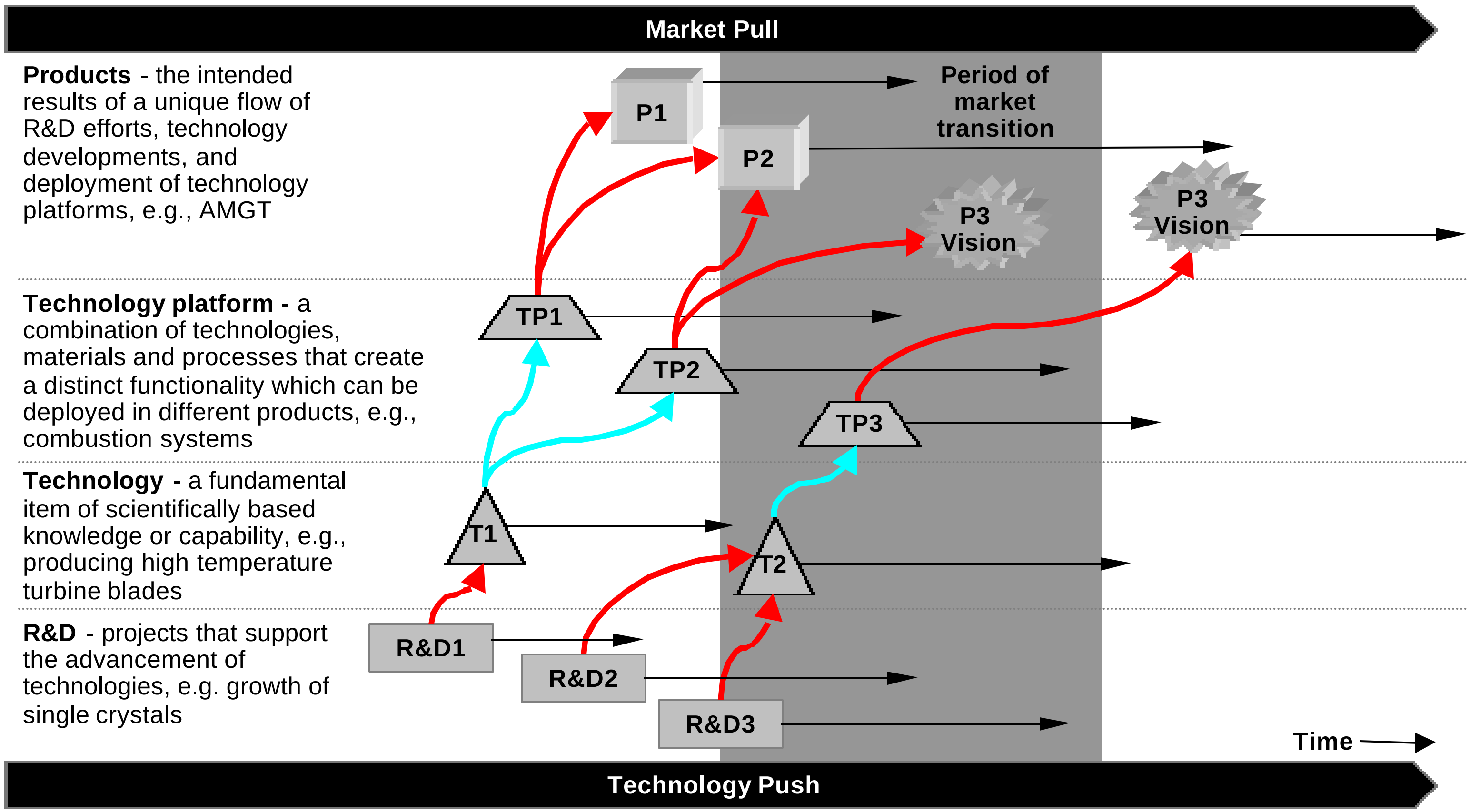
Program Description	Advantages	Disadvantages
Product development program - Similar to ATS program. Gas turbine manufacturers propose specific products for development. A multi-phase program which may include conceptual design, detailed design, and demonstration strategies. Develop policy incentives in later stages of product development to promote end-user adoption.	• Products quickly become commercially available • Clear goals for product development	• More market risk • Costly • Lack of unified support from turbine manufacturers
Delayed program - "Do nothing" approach until the market matures and the uncertainty diminishes.	• Reduced market risk • Reap full benefits of the ATS program • Improved credibility for DOE's programmatic discipline	• Delayed market introduction • May miss the window of opportunity for deploying gas turbines in the U.S.
Policy incentives - Develop policy incentives to maximize overall public benefits, e.g., promote the adoption of efficient generation technologies	• Natural transition to market adoption by providing end-user incentives • Addresses issues of market commercialization in the new electricity industry • Provides incentives to broader technologies and participants	• Difficult to implement • Outside DOE's control • May unfairly penalize other technologies • Cost unknown • Law of unintended consequences
Technology development program - R&D of the underlying technologies and technology platforms using a commitment to product visions rather than product launch. Constant evaluation of the program to keep the R&D projects in-line with the visions of future products as uncertainty diminishes. Introduce programs to reduce commercialization risks during product rollout. Include development programs that support current and emerging products.	• Develop visions of future product attributes flexible enough to address the evolving marketplace needs • Accelerate technology development • Evolution of core engine technologies • Balance market uncertainties and potential public benefits • Potentially applicable to a broad range of current and emerging products	• Viewed as corporate welfare • Could be too broad in scope and run the risk of lacking focus

A technology development program rather than a large demonstration program can be an attractive option in light of the the marketplace uncertainties.

- Technology development programs could balance the market uncertainties while moving towards achieving public benefits.
- Building product-technology roadmaps ensures that R&D efforts in the technology development program are coherent, focused, and aligned with key product attributes.
- Optimal product-technology roadmap development arises from close coordination and linkage of products, technology platforms, technologies, and R&D efforts.
  - *Products*: Develop focused visions of key product attributes (e.g., reduce O&M cost, improve efficiency, etc.).
  - *Technology platforms*: Optimize costs and investments by applying these well-proven building blocks to a variety of products
  - *Technologies*: Develop and expand scientific knowledge or capabilities that enable the deployment of technology platforms
  - *R&D*: Support the underlying work which drives the advancement of technologies

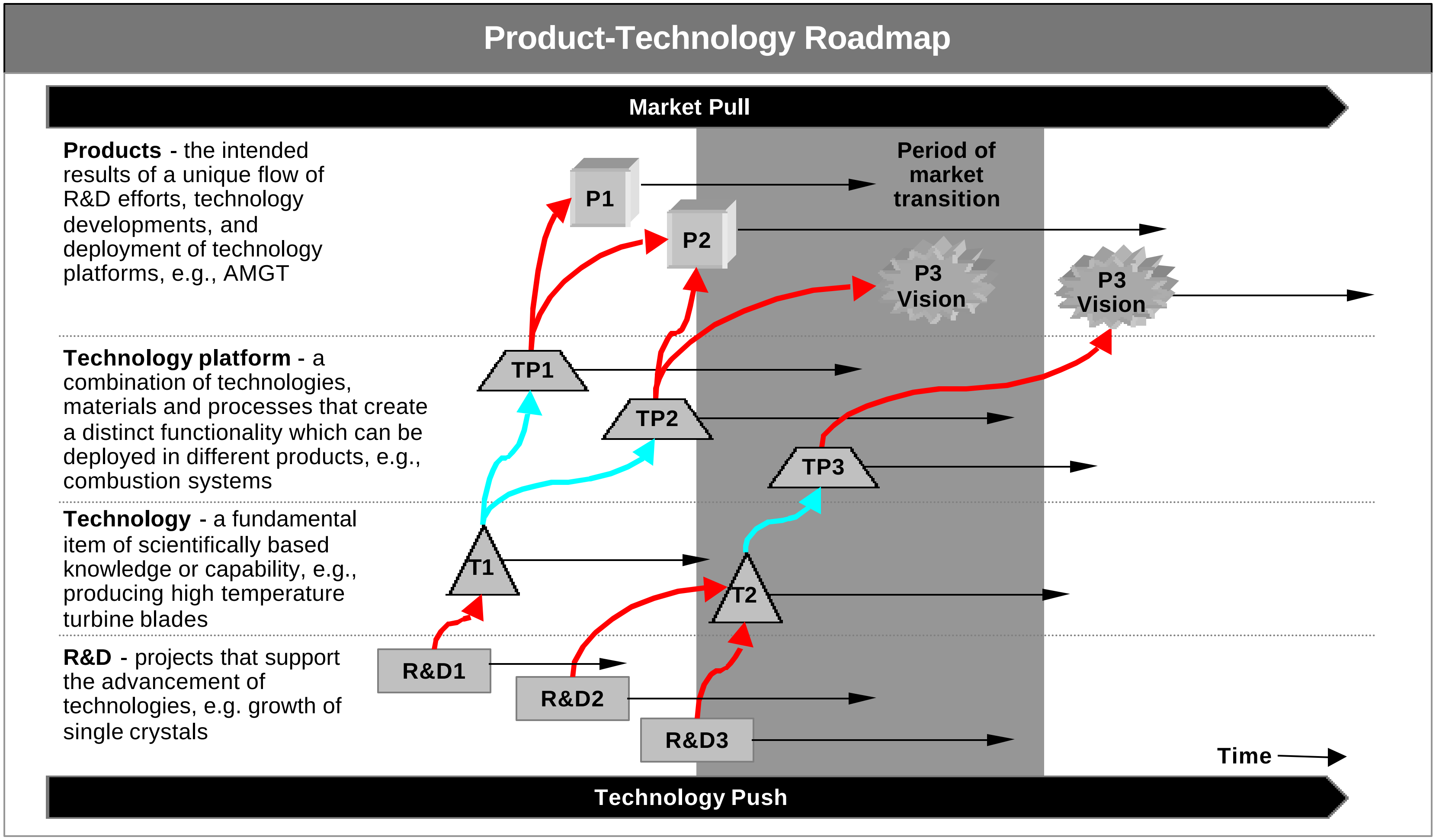
Manufacturers are reluctant to launch a new product during a period of market transitions such as the one we are currently in.

Product-Technology Roadmap



However, they must continue R&D and the development of technology and technology platforms to be able to launch products in the future.

Defining product visions allows R&D efforts to be focused without having to commit to a product launch.



As the market uncertainty diminishes, the product vision can become more refined and eventually transition to a product launch.

Technology development programs would require periodic reviews to ensure the R&D efforts are aligned with the key future product attributes.

- A roadmap is critical to developing product visions and ensuring that the program remains focused and output-oriented.
- As uncertainty diminishes, the desirable and key attributes of future products and product visions would become more apparent.
- This in turn more precisely defines the necessary technology platforms and supporting technologies.
- Therefore, projects in the technology development portfolio need to be reviewed periodically to ensure that the goals of the R&D efforts are aligned with the overall key product attributes.
- Expanding the scope to apply technology development programs to existing or emerging products should also be considered.

Table of Contents

There is significant market potential for the AMGT if it can meet the aggressive technology performance goals.

- The AMGT represents aggressive technology performance goals of 50% LHV efficiency at an installed, capital cost of $250/kW.
- If the AMGT can meet these technology goals however, intermediate load can be an attractive application. With the displacement and load growth market potential in the U.S. reaching 160 GW in the 2005–2015 time frame.
- It does not appear that current technologies (GTCC and SCGT) will satisfy this needs of this market.
- The adoption of this cleaner, more efficient generation technology can lead to significant emissions and fuel savings, with customers benefiting directly from the lower cost of electricity.

However, there are significant uncertainties associated with developing a new product.

- There are considerable market risks associated with the evolving electricity industry requiring new ways for new technologies to be introduced and adopted in the future.
- During the 6–10 years needed to develop the technology, there are substantial uncertainties around the market drivers.
- There are also uncertainties as to whether the AMGT can meet the aggressive technology performance goals.
- Although intermediate load applications appear attractive and current technologies will not be able to satisfy the requirements of this market, most gas turbine manufacturers are reluctant to develop a new product on their own.
- In light of the market and technology risks and the lack of total commitment from turbine manufacturers, technology development programs, which are guided by visions of key attributes in future products, can be the compromised solutions until the uncertainties diminish.

In light of the market and technology risks associated with future products in this current environment and the lack of commitment from turbine manufacturers, technology development programs guided by "product visions" may be the most appropriate basis for a new program.

Table of Contents

The terminology used throughout this report is defined below.

Ancillary Services*	**Regulation**	Generation that is already up and running (synchronized with the power grid) and can be increased or decreased instantly to keep energy supply and energy use in balance
	AGC	Automatic generation control - a generator that responds automatically to the operator to maintain frequency and proper flows into or out of the control area
	Spinning Reserve	Generation that is running, with additional capacity, that can be dispatched within minutes.
	Non-spinning Reserve	Generation that is not running, but can be brought up to speed, within ten minutes.
	Replacement/Operating Reserve	Resources not synchronized to the system but can begin contributing to the grid within a short time, e.g., an hour.
	Black Start	Each Black Start generating unit must be able to start up within ten minutes of issue of a dispatch instruction with a dead primary and station service bus.
Cogen	**High E/T**	High electric to thermal ratio, e.g., peaking, intermediate load, commercial cogen
	Low E/T	Low electric to thermal ratio, e.g., base load, industrial cogen
Green Power	**Cycle Hybrid**	The turbine is integrated into the power generation system.
	Project Integration	The turbine is used to supplement the power from renewable resources. The turbine operates as a backup to Green Power.

* Source: Cal ISO and ISO-NE

Arthur D. Little identified six key market drivers and how these drivers will impact the market potential for an advanced mid-sized gas turbine.

Deregulation

Impact on Market

- Deregulation will expose intermediate load plants to competition.
- The timing of deregulation is likely to create a window of opportunity.

Implications for advanced mid-sized GT development

- Deregulation will determine the best timing for launching a new product.

Gas Price and Availability

Impact on Market

- Level gas prices will help a mid-sized GT compete against existing coal and oil.
- Expanded gas availability will open markets throughout the US.

Implications for advanced mid-sized GT development

- Gas price will drive trade-offs between capital costs and efficiency.

Arthur D. Little identified six key market drivers and how these drivers will impact the market potential for an advanced mid-sized gas turbine. (continued)

Environmental Concerns

Impact on Market

- New air quality standards may force existing plants to early retirement.
- A new mid-sized GT could play a role in meeting CO_2 emissions reduction targets.

Implications for advanced mid-sized GT development

- Emissions and efficiency targets should anticipate regulatory actions.

T&D Constraints

Impact on Market

- The existing T&D infrastructure will constrain wholesale commerce.
- These constraints will create pockets of opportunities for an advanced mid-sized GT.

Implications for advanced mid-sized GT development

- T&D constraints could influence unit size.

Arthur D. Little identified six key market drivers and how these drivers will impact the market potential for an advanced mid-sized GT. (continued)

Nuclear Decommissioning

Impact on Market

- Nuclear decommissioning will create a need for baseload capacity that could be filled with existing intermediate plants.
- This could open markets for new intermediate capacity.

Implications for advanced mid-sized GT development

- This driver could effect the timing for product introduction.

Merchant Plant Activity

Impact on Market

- There are over 50,000 MW of merchant power under development.
- The merchant plant owner could become the dominant customer type.

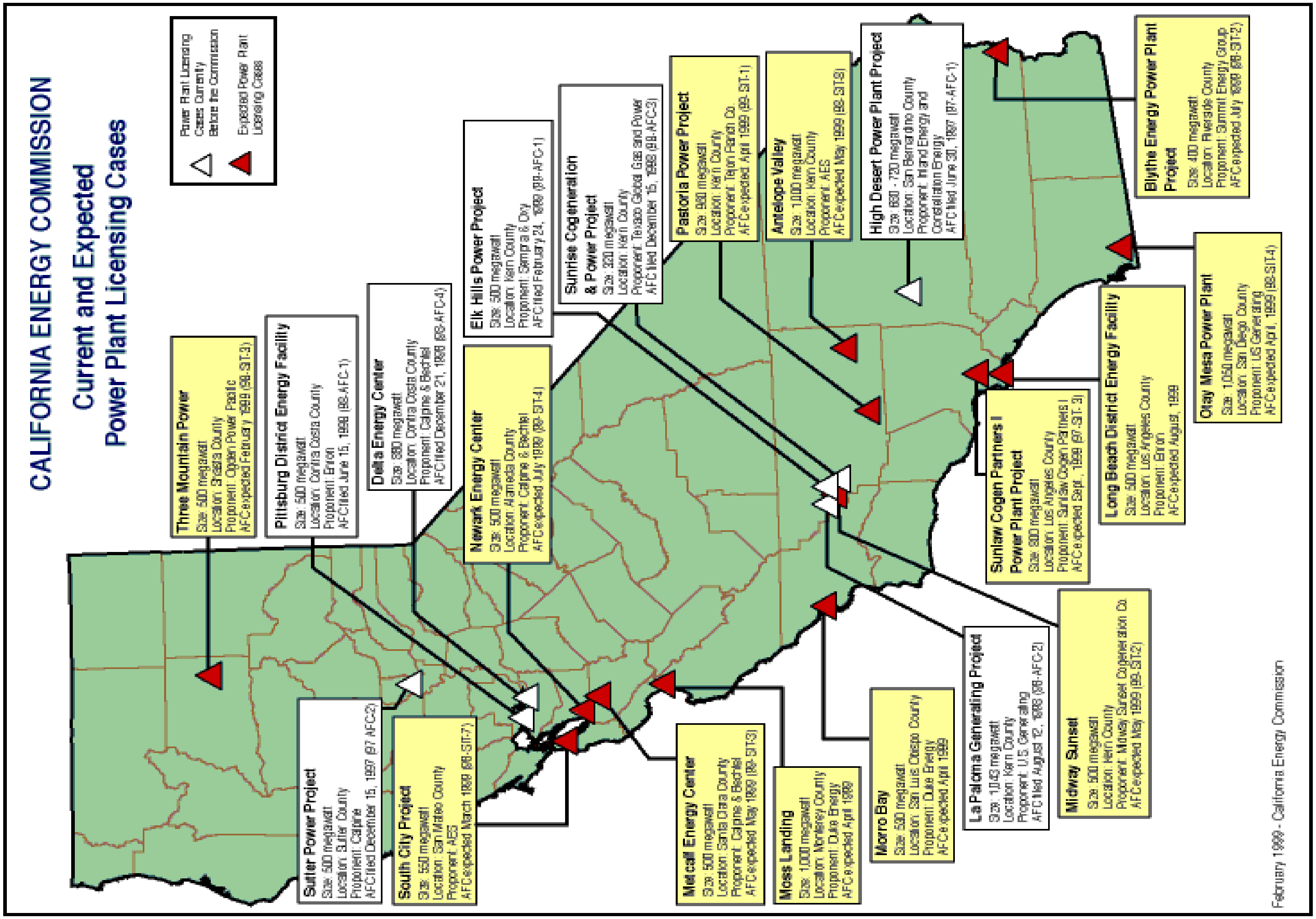
Implications for advanced mid-sized GT development

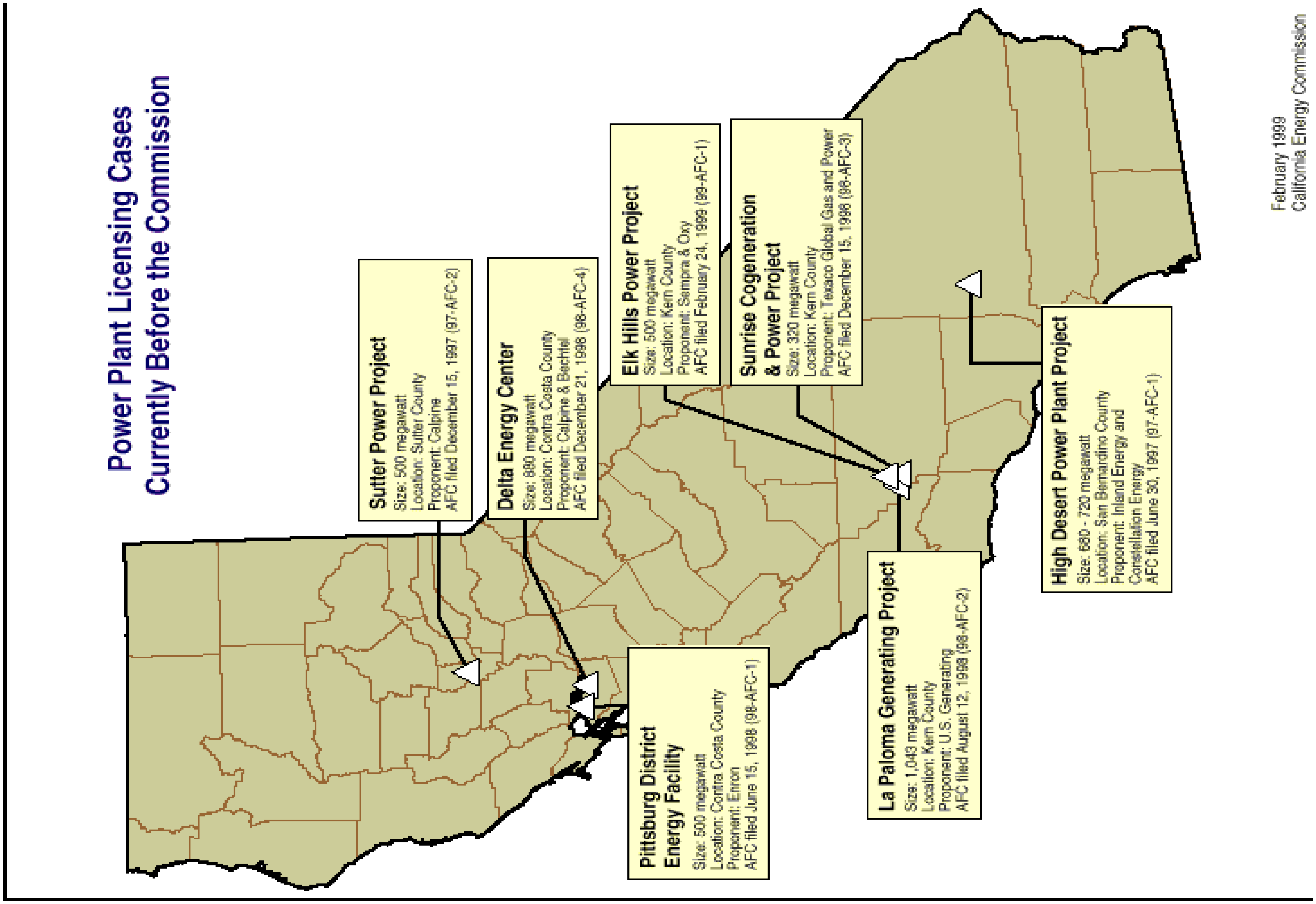
- Mid-sized GT development should focus on reducing technology risk.
- A thorough customer needs assessment should be performed.

Scenarios for the 2005 time frame were developed by considering a range of potential end-states for these market drivers and their impact on the market.

Market Driver	Impact on AMGT	2005 End-State			Impact on AMGT
Deregulation	+	*Nation-wide*	◄──►	*Partial*	+++
Gas Availability	—	*Low*	◄──►	*High*	++
Environmental Pressure	—	*Light Green*	◄──►	*Dark Green*	++
T&D Constraints	0	*Light*	◄──►	*Heavy*	+
Nuclear Decommissioning	+	*Planned*	◄──►	*Accelerated*	+
Merchant Plant Development Activity	+	*Sustained*	◄──►	*Stalled*	++
Overall Load Growth	0	*Low*	◄──►	*High*	+

California Intermediate				
Plant	**Prime Mover**	**Fuel**	**MW**	**Capacity Factor**
Olive/Magnolia	STEAM	GAS	271	7%
Broadway/Glenarm	STEAM	GAS	213	8%
Redding Power	STEAM	GAS	28	9%
Huntington Beach	STEAM	GAS	884	10%
Ormond Beach	STEAM	GAS	1500	12%
STIG - Lodi	GAS TURB	GAS	49	12%
El Centro	STEAM	GAS	256	13%
Etiwanda	STEAM	GAS	926	17%
Grayson	STEAM	GAS	105	17%
Humboldt Bay & Mobile	STEAM	GAS	105	18%
Haynes Generating Station	STEAM	GAS	1570	18%
El Segundo	STEAM	GAS	1020	18%
Woodland	GAS TURB	GAS	48	20%
Almond	COMB CYC	GAS	50	21%
Cool Water	COMB CYC	GAS	482	21%
Morro Bay	STEAM	GAS	1002	22%
Contra Costa	STEAM	GAS	680	22%
Scattergood Generating Station	STEAM	GAS	803	23%
Redondo Beach	STEAM	GAS	1310	25%
Encina	STEAM	GAS	951	26%
Alamitos	STEAM	GAS	1964	27%
Pittsburg	STEAM	GAS	2022	27%
Mandalay	STEAM	GAS	444	31%
Hunters Point	STEAM	GAS	377	31%
Cool Water	STEAM	GAS	143	32%
South Bay	STEAM	GAS	693	35%
Potrero	STEAM	GAS	207	44%
Procter & Gamble	GAS TURB	GAS	117	47%
Moss Landing	STEAM	GAS	1478	50%
Carson Ice	COMB CYC	GAS	60	61%


CALIFORNIA ENERGY COMMISSION
Current and Expected
Power Plant Licensing Cases
Power Plant Licensing Cases Currently Before the Commission
Expected Power Plant Licensing Cases
Three Mountain Power
Size: 500 megawatt
Location: Shasta County
Proponent: Ogden Power Pacific
AFC expected February 1999 (98-SIT-3)
Pittsburg District Energy Facility
Size: 500 megawatt
Location: Contra Costa County
Proponent: Enron
AFC filed June 15, 1998 (98-AFC-1)
Sutter Power Project
Size: 500 megawatt
Location: Sutter County
Proponent: Calpine
AFC filed December 15, 1997 (97-AFC-2)
Delta Energy Center
Size: 880 megawatt
Location: Contra Costa County
Proponent: Calpine & Bechtel
AFC filed December 21, 1998 (98-AFC-4)
South City Project
Size: 550 megawatt
Location: San Mateo County
Proponent: AES
AFC expected March 1999 (98-SIT-7)
Newark Energy Center
Size: 500 megawatt
Location: Alameda County
Proponent: Calpine & Bechtel
AFC expected July 1999 (98-SIT-4)
Elk Hills Power Project
Size: 500 megawatt
Location: Kern County
Proponent: Sempra & Oxy
AFC filed February 24, 1999 (99-AFC-1)
Sunrise Cogeneration & Power Project
Size: 320 megawatt
Location: Kern County
Proponent: Texaco Global Gas and Power
AFC filed December 15, 1998 (98-AFC-3)
Metcalf Energy Center
Size: 500 megawatt
Location: Santa Clara County
Proponent: Calpine & Bechtel
AFC expected May 1999 (99-SIT-3)
Pastoria Power Project
Size: 980 megawatt
Location: Kern County
Proponent: Tejon Ranch Co.
AFC expected April 1999 (99-SIT-1)
Moss Landing
Size: 1,000 megawatt
Location: Monterey County
Proponent: Duke Energy
AFC expected April 1999
Antelope Valley
Size: 1,000 megawatt
Location: Kern County
Proponent: AES
AFC expected May 1999 (98-SIT-8)
Morro Bay
Size: 530 megawatt
Location: San Luis Obispo County
Proponent: Duke Energy
AFC expected April 1999
High Desert Power Plant Project
Size: 680 - 720 megawatt
Location: San Bernardino County
Proponent: Inland Energy and Constellation Energy
AFC filed June 30, 1997 (97-AFC-1)
La Paloma Generating Project
Size: 1,043 megawatt
Location: Kern County
Proponent: U.S. Generating
AFC filed August 12, 1998 (98-AFC-2)
Sunlaw Cogen Partners I Power Plant Project
Size: 800 megawatt
Location: Los Angeles County
Proponent: Sunlaw Cogen Partners I
AFC expected Sept., 1999 (97-SIT-3)
Midway Sunset
Size: 500 megawatt
Location: Kern County
Proponent: Midway Sunset Cogeneration Co.
AFC expected May 1999 (99-SIT-2)
Long Beach District Energy Facility
Size: 500 megawatt
Location: Los Angeles County
Proponent: Enron
AFC expected August, 1999
Blythe Energy Power Plant Project
Size: 400 megawatt
Location: Riverside County
Proponent: Summit Energy Group
AFC expected July 1999 (98-SIT-2)
Otay Mesa Power Plant
Size: 1,050 megawatt
Location: San Diego County
Proponent: US Generating
AFC expected April, 1999 (98-SIT-4)
February 1999 - California Energy Commission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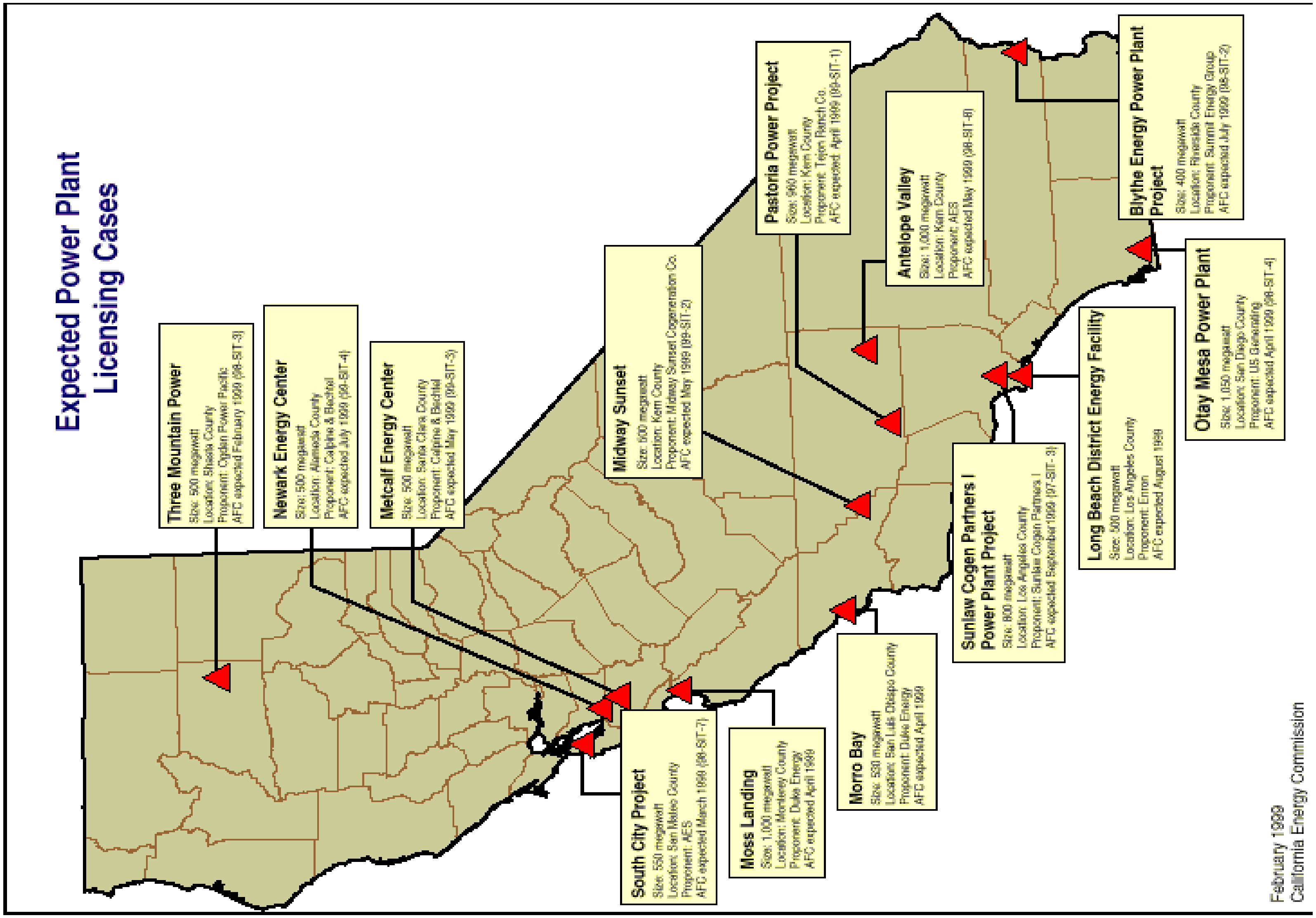
Expected Power Plant Licensing Cases
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Newark Energy Center
Size: 500 megawatt
Location: Alameda County
Proponent: Calpine & Bechtel
AFC expected July 1999 (99-SIT-4)
Metcalf Energy Center
Size: 500 megawatt
Location: Santa Clara County
Proponent: Calpine & Bechtel
AFC expected May 1999 (99-SIT-3)
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Size: 500 megawatt
Location: Kern County
Proponent: Midway Sunset Cogeneration Co.
AFC expected May 1999 (99-SIT-2)
South City Project
Size: 550 megawatt
Location: San Mateo County
Proponent: AES
AFC expected March 1999 (98-SIT-7)
Moss Landing
Size: 1,000 megawatt
Location: Monterey County
Proponent: Duke Energy
AFC expected April 1999
Pastoria Power Project
Size: 960 megawatt
Location: Kern County
Proponent: Tejon Ranch Co.
AFC expected April 1999 (99-SIT-1)
Morro Bay
Size: 530 megawatt
Location: San Luis Obispo County
Proponent: Duke Energy
AFC expected April 1999
Antelope Valley
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Location: Kern County
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Size: 1,050 megawatt
Location: San Diego County
Proponent: US Generating
AFC expected April 1999 (98-SIT-4)
February 1999
California Energy Commission

New England Intermediate Plants				
Plant	**Prime Mover**	**Primary Fuel**	**Capacity (MW)**	**CF**
Montville 5-6	STEAM	OIL	492	9%
W.F. Wyman #1-3	STEAM	OIL	225	10%
W.F. Wyman #4	STEAM	OIL	617	10%
Bridgeport Harbor 1,2	STEAM	OIL	255	12%
Middletown 1-4	STEAM	OIL	828	13%
West Springfield1-3	STEAM	GAS	212	15%
Kendall Square1-3	STEAM	GAS	65	17%
Salem Harbor 4	STEAM	OIL	400	26%
Mystic #7	STEAM	OIL	592	28%
Mystic #4-6	STEAM	OIL	388	28%
Newington	STEAM	OIL	411	32%
Norwalk Harbor1-2	STEAM	OIL	333	32%
Canal #1	STEAM	OIL	562	39%
Canal #2	STEAM	GAS	556	39%
New Haven Harbor	STEAM	OIL	466	41%
Brayton Point 4	STEAM	OIL	444	43%
New Boston 1-2	STEAM	GAS	760	46%
Devon7-8	STEAM	GAS	216	50%
Schiller Station 4-6	STEAM	COAL	146	68%
Ocean State Power Unit 2	COMB CYC	GAS	288	68%
Northeast Energy Asso 1 & 1	COMB CYC	GAS	302	74%
Ocean State Power Unit 1	COMB CYC	GAS	288	74%
Manchester Street (96)	COMB CYC	GAS	458	83%

Proposed/Planned Interconnection

(and Long Term Firm Point To Point Transmission Service)

(In order of application for study execution of study agreement)

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Date of Completed application | **Project Description** | **Applicant Information** | **Study Status**

Preliminary - dates are under review		**Projects**	**MW**	**Town**	**State**	**In-Service Date**	**Proposed Interconnection Pt**	**Company Name**	**Address**	**City**	**State**	**Zip**	**Phone**	**Fnsh**	**Study report available**
**	07-Jun-96	Millennium	400	Charlton	MA	June 2000	W 123 115 KV	US Generating Company	One Bowdoin Square	Boston	MA	02114	(617)720-7654	Y	New England Electric Power
**	08-Nov-96	EMI-Tiverton	265	Tiverton	RI	2000	Near Tiverton 115 KV	Energy Management Inc.	One Energy Rd.	North Dartmouth	MA	02747	(508)998-8515	Y	Eastern Utilities
**	13-Feb-97	Androscoggin Energy Center	157	Jay	ME	October-99	Jay Substation	SkyGen Energy LLC	650 Dundee Rd Suite 150	Northbrook	IL	60010	(847)559-9800	Y	Central Maine Power
	10-Apr-97	EMI Dighton Power Project	185	Dighton	MA	May 1999	EUA system on the U6 115 kV transmission line	Energy Management Inc.	One Energy Rd	North Dartmouth	MA	02747	(508)998-8515	Y	Eastern Utilities
**	09-May-97	Brayton Pt	477	Somerset	MA	2001	Brayton PT Station	USGen New England	One Bowdoin Square	Boston	MA	02114-2910	(617)720-7654	Y	New England Electric Power
**	12-Jun-97	Rumford Power Associates	265	Rumford	ME	April 2000	Will replace the current Rumford Substation	Energy Management Inc.	One Energy Rd.	North Dartmouth	MA	02747	(508)998-8515	Y	Central Maine Power
**	25-Jun-97	Bridgeport Harbor Station	520	Bridgeport	CT	June 1999	Use existing Bridgeport Hbr Station & Interconnecting to the Pequonnock Subs	Bridgeport Energy, LLC	801 Bridgeport Ave.	Shelton	CT	06484	(203)926-4447	Y	United Illuminating

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**	15-Jul-97	ANP Bellingham Energy Project	580	Bellingham	MA	2000	Bellingham adjacent to NEP's 303,345 KV Row-Brayton PT. X W. Medway.	American National Power	65 Boston Post Road West Suite 300	Marlborough	MA	01752	(508)786-7200	Y	New England Electric Power
**	15-Jul-97	ANP Blackstone Energy Project	580	Blackstone	MA	2000	Blackstone site near Beco's 345 KV, 336 ROW Sherman RD X NEA tap	American National Power	65 Boston Post Road West Suite 300	Marlborough	MA	01752	(508)786-7200	Y	New England Electric Power
	22-Jul-97	IDC Bellingham	1035	Bellingham	MA	2001/2002	Beco 345 kV line between West Medway and Sherman Rd Substations	Infrastructure Develop. Corp.	350 Lincoln Place Suite 111	Hingham	MA	02043	(781)749-9800		
	24-Jul-97	Maine Independence	500	Veazie	ME	April 1 , 2000	Located at the Graham Station in Veazie , ME	Casco Bay Energy Co.	79 Federal St.	Brunswick	ME	04011	(207)729-8255		Draft Report from CMP
*	05-Aug-97	Wareham		Wareham	MA	February 2001	Adjacent to the Tremont Substation	Energy Management Inc.	One Energy Rd.	North Darmouth	MA	02747	(508)998-8515		
	15-Aug-97	Berkshire Power	276	Agawam	MA	1999	1782, 115KV line South Agawam JCT	PDC Berkshire Power LLc	200 High St 5th Floor	Boston	MA	02110	(617)747-9100	Y	Northeast Utilities
	22-Aug-97	Milford Power	540	Milford	CT	1st Quarter 2000	Adjacent to Devon Substation	PDC Power Development Co. LLC	200 High St.	Boston	MA	-02110	(617)443-1900		
	22-Aug-97	Summit Power	276	Westfield	MA	1st Quarter 2001	1302, 115 KV line Between Buck pond 348 & Agawam 18C Subs	PDC Power Development Co. LLC	200 High St.	Boston	MA	02110	(617)443-1900		

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	30-Sep-97	Cabot Power	350	Everett	MA	June 2000	Mystic 345 KV	Cabot Power Corp.	75 State St.	Boston	MA	02109	(617)526-8490		
	09-Oct-97	South Norwalk	175	South Norwalk	CT	January 1 2000	Norwalk 115 KV	GKO INC.	7630 Little River Turnipike Suite 306	Annandale	VA	22003	(703)941-0532		
	24-Oct-97	ANP Gorham	850	Portland	ME	July 1,2000	S.Gorham 345 KV	American National Power	65 Boston Post Road West Suite 300	Marlborough	MA	01752	(508)786-7200		Draft Report from CMP
	12-Dec-97	Lake Road Generating	810	Killingly	CT	June 2001	345 kV Between towers 9260-9265 on line 347 of NU	Lake Road Generating Co. L.P.	One Bowdoin Square	Boston	MA	02114	(617)720-7615		
	12-Dec-97	SEI Newington	525	Newington	NH	February 2000	345 KV Newington Substation.	Southern Energy , Inc.	900 Ashwood Parkway - Suite 500	Atlanta	GA	30338	(770)379-6953		
	13-Jan-98	Piscataqua Power	700	Newington	NH	January 1 2000	Newington Station 345 Kv	Tractebel Energy Marketing,Inc.	1177 West Loop South, suite 900	Houston	TX	77027	(713)552-2248		
	13-Jan-98	Versaille Energy Center	240	Versaille	CT	2000	Tunnel 115 KV	SkyGen Energy LLC	650 Dundee Rd. Suite 150	Northbrook	IL	60062	(847)559-9800		
*	13-Jan-98	White Mountain Cogen.Center		Groveton	NH	2000	Lost Nation 115 kV	SkyGen Energy LLC	650 Dundee Rd suite 150	Northbrook	IL	60062	(847)559-9800		
	14-Jan-98	Livermore Falls	40	Livermore	ME	December 1,2000	Livermore Falls 115 KV	SkyGen Energy LLC	650 Dundee Rd. Suite 150	Northbrook	IL	60062-2753	(847)559-9800		

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*	20-Jan-98	Housatonic Power		Sherman	CT	January 1, 2001	Interconnection to be on the 345 kV between Pleasant Valley, NY and Ln Mtn	Tractebel Energy Marketing, Inc.	1177 West Loop South, suite 900	Houston	TX	77027	(713)552-2248		
	11-Feb-98	AES Londonderry	742	Londeonderry	NH	July 2001	Scobie 345 KV	AES Enterprise Inc.	233 Needham St.	Newton	MA	02164	(617)454-1288		
	11-Feb-98	Wallingford Power	550	Wallingford	CT	2000/2001	Adjacent to Wallingford Substation 115 KV	Wallingford Department of Util.	100 John St.	Wallingford	CT	06492	(203)265-1594		
	16-Feb-98	Meriden Power	544	Meriden	CT	3rd Quarter 2001	One unit on the 362 line , 1 unit on the 348 line.	PDC Meriden Power Co..	200 High St.	Boston	MA	02110	(617)747-9100		
	19-Feb-98	HQ-Surowiec	600	Pownal	ME	2002	Surowiec 345 KV or MEPCO	Central Maine Power	83 Edison Drive	Augusta	ME	04336	(207)626-9750		
	25-Feb-98	Orrington Generation	700	Orrington	ME	Mid 2001	Connected to Orrington Maine 345 KV bus	Orrington Generation Partners	250 West Pratt St.	Baltimore	MD	21202	(410)783-3654		
*	27-Feb-98	Patriot Power		Taunton	MA	Ist Quarter 2001	Bridgewater 345 KV Line	Duke Energy Power Services	400 S. Tryon St.	Charlotte	N.C.	28201-1007	(713)627-6551		
*	06-Mar-98	S&P Cogeneration		Lynn	MA	4th Quarter 2001	Lynn 115 KV	West Lynn Creamery	626 Lynn Way	Lynn	MA	01905	(617)599-1300		
	13-Mar-98	AES Carpenter	700	Southington	CT	2001	Southington 345 KV	AES Enterprise Inc.	233 Needham St.	Newton	MA	02164	(617)454-1288		
	18-Mar-98	Newington Energy Center	520	Newington	NH	1st Quarter 2001	Newington 345 KV	Duke Energy Power Services	400 S. Tryon St.	Charlotte	N.C.	28201-1007	(704)373-6622		

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	24-Mar-98	Bucksport Energy, L.P.	174	Bucksport	ME	1999	Belfast 115 KV bus	Preti,Flaherti,Beliveu & Pachios LLC	45 Memorial Circle	Augusta	ME	04332-1058	(207)623-5300		
	25-Mar-98	Engage Energy LTF PtP	300			2000	Import from New Brunswick via MEPCO	Engage Energy US, L.P.	One Harbour Place suite 225	Portsmouth	NH	03801	(603) 433-6175		
	25-Mar-98	Norwich Power Station	500	Norwich	CT	December 2000	Bean Hill Substation	Connecticut Mun.Elec..	30 Stott Ave.	Norwich	CT	06360	(860)889-4088		
	26-Mar-98	Tuspani Power	350	North Smithfield	RI	2000/2001	W.Farnum 345 KV	INDECK	600 N.Buffalo Grove RD.Suite 300	Buffalo Grove	IL	60089	(561)575-1457		
	30-Mar-98	Towantic Energy	540	Oxford	CT	2001/2002	Beacon Falls 115 KV	Arena Capital L.T.D.	16 Beachside Common	Westport	CT	06880	(203)221-7520		
	31-Mar-98	Sithe Edgar Station Expansion	1500	Weymouth	MA	2001	Holbrook 345 KV	Sithe New England Inc.	Mystic Power Station 173 Afford St.	Charlestown	MA	02129	(617)369-6707		
*	31-Mar-98	Sithe Framingham Station Expansion		Framingham	MA	2001	Framingham 230 KV	Sithe New England Inc.	Mystic Power Station 173 Afford St.	Charlestown	MA	02129	(617)369-6707		
	31-Mar-98	Sithe Medway	540	West Medway	MA	2001	Existing Medway Station 345 KV	Sithe New England Inc.	173 Alford St.	Charlestown	MA	02129	(617)369-6707		

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	31-Mar-98	Sithe Mystic Station Expansion	1750	Charlestown	MA	2001	Mystic 345 KV	Sithe New England Inc.	Mystic Power Station 173 Afford St.	Charlestown	MA	02129	(617)369-6707		
	31-Mar-98	Westbrook Power	520	Westbrook	ME	March 2000	Spring St. Substation 115 KV	Westbrook Power L.L.C.	1040 Great Plain ave.	Needham	MA	02152	(781)444-5580		
	02-Apr-98	Wyman A	550	Wyman	ME	January 2 2000	Connected at the Wyman Substation	FPL Energy Inc.	700 Universe Blvd Box 14000	Juno Beach	FL	33408-2683	(561)691-7171		
	02-Apr-98	Wyman B	550	Wyman	ME	January 3 2000	Connected at the Wyman Substation	FPL Energy Inc.	700 Universe Blvd Box 14000	Juno Beach	FL	33408-2683	(561)691-7171		
	02-Apr-98	Mason	550	Wiscasset	ME	2000	Mason 345 KV	FPL Energy Inc.	700 Universe Blvd Box 14000	Juno Beach	FL	33408-2683	(561)691-7171		
	14-Apr-98	FPL Energy	250	New Bedford	MA	November 2000	Industrial Park 115 KV	ESI New Bedford L.L.C.	11760 US Highway One Suite 600	North Palm Beach	FL	33408	(561)691-3514		
	29-Apr-98	R.I. Hope Energy	500	Johnston	RI	Spring 2001	Kent 345 KV	Houston Ind. Power Generation	1111 Louisiana 16th Floor	Houston	TX	77002	(713)207-7731		
	08-May-98	Rocky River Power	530	New Mildford	CT	July 2001	Long Mountain 345 KV	Sempra Energy Resources	101 Ash St.	San Diego	CA	92101	(619)696-2925		

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Date of Completed application		Project Description							Applicant Information					Study Status	
Preliminary - dates are under review		Projects	MW	Town	State	In-Service Date	Proposed Interconnection Pt	Company Name	Address	City	State	Zip	Phone	Fnsh	Study report available
	28-May-98	CVPS/GMP LTF PtP	600	Plattsburg	NY	December 2001	Import from NY via PV20	Green Mountain Power Corp	25 Green Mountain Drive	Burlington	VT	05402	(802)660-5621		
	28-May-98	HQ Highgate2 HVDC	600	Highgate	VT	December 2001	Located on the Hydro Quebec sys. N. near Highgate, VT	Green Mountain Power Corp.	25 Green Mountain Drive	Burlington	VT	05402	(802)660-5621		
	01-Jun-98	Glen Charlie Unit One	500	Wareham	MA	Spring 2001	Wareham Substation	B-W Energy LLC	101 Rogers St.	Cambridge	MA	02142	(617)494-6133		
	04-Jun-98	Canal Unit 3	561	Sandwich	MA	2nd Quarter 2001	Canal Substation in Sandwich, MA	Southern Energy	900 Ashwood Parkway	Atlanta	GA	30338	(770)279-6953		
	6/5/98	Wiscassett	1400	Wiscassett	ME	Oct, 2001	Existing Maine Yankee Site	Stone & Websters Engineers	245 Summer St	Boston	MA	02210	(617) 589-1208		
	08-Jun-98	Tractebel LTF PtP	300			2002	Import from the New Brunswick System	Tractebel Energy Marketing	24 Bridge St,	Concord	NH	03301	(603)225-4523		
	10-Jul-98	Brockton Power Project	272	Brockton	MA	January 2001	Industrial Blvd.	Brockton Power LLC	142 Crescent St.	Brockton	MA	02402	(508)586-1115		
	17-Jul-98	Kendall Repowering Project	172	Cambridge	MA	Third Quarter 2001	Kendall Station in Cambridge	Southern Company	900 Ashwood Parkway	Atlanta	GA	30338	(770)379-7000		
	18-Aug-98	Campello Power Co.	285	Brockton	MA	2 nd Quarter 2002		Generation Venture Associates	73 Tremont St.	Boston	MA	02108	(617)720-2240		
	26-Aug-98	Nickel Hill Energy Project	750	Dracut	MA	Mid 2001	Connected to the Tewksbury 230 KV Bus	Constellation Power Development Inc.	250 W. Pratt St. 23rd Floor	Baltimore	MD	21201	(410)783-3619		
	09-Sep-98	Bennington Energy Park	270	Bennington	VT	November 2001		Vermont Power & Energy Develop. Corp.	Box 2	Rutland	VT	05702	(802)223-3080		

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Date of Completed application		Project Description							Applicant Information					Study Status	
Preliminary - dates are under review		Projects	MW	Town	State	In-Service Date	Proposed Interconnection Pt	Company Name	Address	City	State	Zip	Phone	Fnsh	Study report available
	09-Sep-98	Rutland Energy Park	1080	Rutland	VT	November 2001		Vermont Power and Energy Develop. Corp.	BOX 2	Rutland	VT	05702	(802)223-3080		
	14-Sep-98	Irving Oil LTF PtP	250			April 1,2001	Import from NB Via MEPCO	Irving Oil Limited	P.O. Box 1421 , 10 Sydney St.	Saint John	NB	e0g 1z0	(506)632-7167		
	29-Oct-98	Patriot Cabot Street Station	300	Holyoke	MA	2000/2001	Holyoke Substation	Patriot Power LLC	917 Willow Ave. Suite 2 R	Hoboken	NJ	07030	(201)222-7980		
	13-Nov-98	Haddam Station Phase I	600	Haddam Neck	CT	2001/2002	Site of the Former CT Yankee Plant	Connecticut Yankee Atomic Power CO.	362 Injun Hollow Rd	East Hampton	Ct	06424	(860) 267-3601		
	11/13/98	Haddam Station Phase II	600	Haddam Neck	CT	2001/2002	Site of the Former CT Yankee Plant	Connecticut Yankee Atomic Power CO.	362 Injun Hollow Rd	East Hampton	CT	06424	(860) 267-3601		
	1/5/99	Redington Mountain Wind Farm	30	Carrabassett	ME	Dec 2001/Dec 2002	Bigelow Substation	Redington Mountain Windpower, L.L.C	9 Castle Rd.	New Gloucester	ME	04260	(207)926-4898		
	1/21/99	Cross Sound Cable	600	New Haven	CT	May 1, 2002	HVDC to Shoreham, NY New Haven CT adjacent to UI East Shore Station	TransEnergie U.S. Ltd.	110 Turnpike Rd. Suite 300	Westborough	MA	01582	(508)870-9900		
*		WEG-Norwich		Norwich	CT	2001	Montville 345 KV	Williams Energy Group	Box 3448 One Williams Center	Tulsa	OK	74101-3348	(918)588-3380		
			32376												

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Texas ERCOT Intermediate				
Plant	**Type**	**Fuel**	**Capacity (MW)**	**Capactity Factor**
Deepwater (TX)	STEAM	GAS	179	7%
Eagle Mountain	STEAM	GAS	665	11%
Parkdale	STEAM	GAS	327	11%
Holly Street	STEAM	GAS	567	12%
Bryan (TX)	STEAM	GAS	138	12%
R.W. Miller	GAS TURB	GAS	208	12%
Sam Bertron	STEAM	GAS	808	13%
V.H. Braunig	STEAM	GAS	855	13%
Collin	STEAM	GAS	153	15%
Paint Creek	STEAM	GAS	237	15%
Spencer	STEAM	GAS	179	17%
Si Ray	STEAM	GAS	154	18%
Webster (TX)	STEAM	GAS	374	18%
Handley	STEAM	GAS	1441	20%
O.W. Sommers	STEAM	GAS	880	22%
Victoria (TX)	STEAM	GAS	441	23%
T.H. Wharton	STEAM	GAS	1152	23%
Lake Creek (TX)	STEAM	GAS	323	24%
North Lake	STEAM	GAS	715	24%
Trinidad (TX)	STEAM	GAS	244	24%
Decker Creek	STEAM	GAS	740	26%
Mountain Creek	STEAM	GAS	893	26%
Lake Hubbard	STEAM	GAS	921	27%
Greens Bayou	STEAM	GAS	406	28%
Valley (TX)	STEAM	GAS	1115	29%
E.S. Joslin	STEAM	GAS	261	30%
Sam Gideon	STEAM	GAS	631	30%
Lon C. Hill	STEAM	GAS	574.2	32%
P.H. Robinson	STEAM	GAS	2260	32%
T.C. Ferguson	STEAM	GAS	420	33%
Morgan Creek	STEAM	GAS	822	37%
Stryker Creek	STEAM	GAS	685	39%

Texas ERCOT Intermediate				
Plant	**Type**	**Fuel**	**Capacity (MW)**	**Capactity Factor**
Cedar Bayou	STEAM	GAS	2220	39%
Graham	STEAM	GAS	630	41%
J.L. Bates	STEAM	GAS	188.7	41%
Ray Olinger	STEAM	GAS	335	41%
R.W. Miller	STEAM	GAS	391	44%
Tradinghouse Creek	STEAM	GAS	1383	45%
Laredo	STEAM	GAS	187.2	46%
Dansby	STEAM	GAS	105	47%
Permian Basin	STEAM	GAS	655	48%
Fort Phantom	STEAM	GAS	362	49%
North Oak Creek (TX)	STEAM	GAS	85	51%
Barney M. Davis	STEAM	GAS	703	52%
Nueces Bay	STEAM	GAS	531	52%
Decordova	STEAM	GAS	818	55%
La Palma	STEAM	GAS	163.2	56%
Rio Pecos	STEAM	GAS	137	57%
Parish	STEAM	GAS	3517	62%
Big Brown	STEAM	COAL	1150	62%
Monticello (TX)	STEAM	COAL	1880	65%
Deely	STEAM	COAL	810	67%
San Angelo	COMB CYC	GAS	125	74%
Fayette (TX) (Sam Seymour)	STEAM	COAL	1616	75%
Gibbons Creek	STEAM	COAL	462	75%
Coleto Creek	STEAM	COAL	600.39	79%
Dupont (San Jacinto SES)	GAS TURB	GAS	176	81%
Martin Lake	STEAM	COAL	2250	81%
San Miguel	STEAM	COAL	391	82%
Oklaunion	STEAM	COAL	676.54	82%
J.K. Spruce	STEAM	COAL	530	82%
Limestone (TX)	STEAM	COAL	1440	86%
TNP One	STEAM	COAL	297	89%
Sandow 4	STEAM	COAL	545	93%

Under Construction in ERCOT

TX (Gregory)—300-400 MW gas-fired cogeneration facility at Reynolds Metals' Sherwin alumina production plant near Corpus Christi—original developer LG&E Power joined by co-developer Columbia Electric (unit of Columbia Energy Group) 6/98 to form Gregory Power Partners—construction began 8/98 with Bechtel as EPC—COD 6/2000

TX (Grimes Co.)—Tenaska is the lead developer for a 830 MW gas-fired, combined cycle project called Tenaska Frontier, near Shiro—project partnership includes Tenaska, Continental Energy Services (unit of Montana Power) and Illinova Generating—project will interconnect with ERCOT via HLP's 345 kV transmission line and with grids outside ERCOT via Entergy's 345 kV line and will market into ERCOT and all of the Eastern Interconnect—equipment includes three GE Frame 7FA gas turbines, three HRSGs and one GE steam turbine—construction began 9/1/98 —COD 2000

TX (Ingleside)—Occidental Energy Ventures and Conoco Global Power are developers—Ingleside Cogeneration L.P. 440 MW gas-fired cogeneration plant—steam production (1,100 kpph of process steam) and up to 235 MW generation capacity to be sold to adjacent chemical plants owned by affiliates Oxychem and DuPont—construction start early 1998—26E 7FA gas turbines, ABB steam turbine—EPC by Duke/Fluor Daniels—COD expected 1/2000

TX (Midlothian)—American National Power has begun construction of 1,100 MW gas-fired, combined cycle plant—output sold to Texas Utilities Electric for two years from COD in 2000 to 2002

Under Development in ERCOT

TX (Edinburg)—1,000 MW gas-fired combined cycle facility—co-developers are American National Power and US Generating—construction to be in two phases of 500 MW each, with COD for Phase 1 in summer of 2001

TX (Edinburg)—700 MW gas-fired combined cycle Magic Valley facility being developed by Calpine Corp.—increased from 430 MW following award of Magic Valley Coop RFP to Calpine COD 2001—construction to begin 4thQ 1999

TX (Mission)—CSW plans to develop the gas-fired 500 MW Frontera project in the Rio Grande Valley—construction to begin 8/98, with COD for 2 170 MW units in summer 1999 and full COD by end of 1999

TX (Pasadena)—Calpine has announced plans to add 510 MW to its existing facility (Currently Operational), increasing the total to 750 MW

TX (Ennis) -- Tractebel Power plans to build 350 MW gas-fired combined cycle plant, Tractebel's first in

Under Development in ERCOT (cont'd)

TX (Houston)—Dynegy plans to add 155 MW to existing 610 MW CoGen Lyondell plant—new capacity to be available for merchant market beginning 6/2000

TX (Marion)—Panda Energy has announced plants to develop a gas-fired, 740 MW Panda Guadalupe facility

TX (Orange)—Air Liquide America and Houston Industries Power Generation have formed a 50/50 partnership to develop a gas-fired 100 MW cogeneration plant at a Bayer Corp.'s Sabine synthetic rubber manufacturing plant—construction to begin 8/98 with COD 11/99—

TX (Paris)—Panda Energy has announced plans to construct a 1,000 MW gas-fired plant—construction o begin 1/99 and be completed 6/2000

TX (Three Rivers)—U.S. Generating and Ultramar Diamond Shamrock—as part of planned 7 year, $2 billion alliance between PG&E and UDS, U.S. Generating plans to build 750 MW gas-fired cogeneration facility at UDS refinery

TX—American National Power has stated intention to build a total of 4,000 MW in TX

The cost and efficiency assumptions for the market potential analysis are presented below.

Technology	Capital Cost [$/kW]	Efficiency [LHV]	Capital Carrying Charge [$/kW/yr]	Marginal Cost [$/MWH]
SCGT	280	38%	44	30.4
GTCC	500	61%	78	20.8
AMGT	250	47%	39	25.5
AMGT	250	50%	39	24.3

Load growth is added to displacement market to arrive at the overall AMGT market potential in the 2005–2015 time frame.

	2005–2015 Displacement Market Potential (MW)		Annual Capacity Growth[1] (%)	2005–2015 Displacement and Load Growth Market Potential (MW)	
	Pessimistic	Optimistic		Pessimistic	Optimistic
California	1,800	10,500	1.6	2,000	14,000
New England	1,700	6,700	1.3	1,900	8,400
Texas	11,000	32,000	2.0	12,900	45,700
WSCC (less CA)	580	3,400	1.6	700	4,500
MAPP	200	1,200	1.7	200	1,900
SPP	11,800	34,200	1.5	13,200	44,700
MAIN	1,200	7,000	1.5	1,400	9,200
ECAR	700	4,000	1.6	800	5,400
SERC	100	760	2.3	200	1,100
FRCC	1,300	7,400	2.1	1,500	10,800
MAAC	900	5,000	1.3	1,000	6,300
New York	1,200	7,000	1.3	1,300	8,800

[1] Annual capacity growth projections from NERC “Reliability Assessment 1997-2007”

The heat rate and emission factors for AMGT and generation technologies being displaced are presented below.

		2005	2010	2015
AMGT	Heat Rate (Btu/kWh)	7,988	7,741	7,509
	CO_2 Emission Factor (MMTon/Trillion BTU)	0.055	0.055	0.055
	SO_x Emission Factor (MMTon/Trillion BTU)	0	0	0
	NO_x Emission Factor (MMTon/Trillion BTU)	$2x10^{-5}$	$2x10^{-5}$	$2x10^{-5}$
Displaced Technologies	Heat Rate (Btu/kWh)	10,273	10,019	9,771
	CO_2 Emission Factor (MMTon/Trillion BTU)	0.065	0.065	0.065
	SO_x Emission Factor (MMTon/Trillion BTU)	0.0004	0.0004	0.0004
	NO_x Emission Factor (MMTon/Trillion BTU)	0.0001	0.0001	0.0001